LG&E

Louisville Gas and Electric Company
220 West Main Street (40202)
P.O. Box 32010
Louisville, Kentucky 40232

March 1, 2004

RECEIVED

MAR 01 2004

PUBLIC SERVICE
COMMISSION

Mr. Thomas Dorman, Executive Director
Public Service Commission
211 Sower Boulevard
P. O. Box 615
Frankfort, Kentucky 40601

Re: ***A REVIEW OF THE ADEQUACY OF KENTUCKY'S GENERATION CAPACITY AND TRANSMISSION SYSTEM - ADM. CASE NO. 387***

Dear Mr. Dorman:

Pursuant to Appendix G of the Commission's Order dated December 20, 2001 in the above styled case, enclosed are an original and five (5) copies of the 2003 Annual Resource Assessment Filing of Louisville Gas and Electric Company.

Also filed herewith is a Petition for Confidential Protection regarding certain information provided in response to Item No. 11.

Very truly yours,

John Wolfram

John Wolfram
Manager, Regulatory Affairs

Enclosures

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

RECEIVED

MAR 0 1 2004

PUBLIC SERVICE COMMISSION

In the Matter of:

A REVIEW OF THE ADEQUACY OF KENTUCKY'S GENERATION CAPACITY AND TRANSMISSION SYSTEM	)))	**ADMINISTRATIVE CASE NO. 387**

PETITION OF
LOUISVILLE GAS AND ELECTRIC COMPANY
FOR CONFIDENTIAL PROTECTION

Louisville Gas and Electric Company ("LG&E"), by counsel, petitions the Kentucky Public Service Commission ("Commission") pursuant to 807 KAR 5:001 Section 7 to grant confidential protection to certain information filed pursuant to Appendix G of the Commission's Order of December 20, 2001.

In support of this petition, LG&E states as follows:

1. On December 20, 2001, the Commission issued an Order with its findings following an investigation and review of the adequacy of Kentucky's generation capacity and transmission system. In an effort to continue monitoring these issues, the Commission ordered Kentucky's six major jurisdictional electric utilities to file certain planning-related information, as defined in Appendix G to the Commission's December 20, 2001 Order, by March 1st of each year and by July 1st of each year. In Item No. 11, the Commission ordered LG&E and the other jurisdictional electric utilities to provide information concerning scheduled outages or retirements of generating capacity.

2. In connection with the information provided in response to Item No. 11, the Commission has ordered LG&E to provide details of scheduled outages or retirements of generating capacity for current year and the following four years. LG&E is requesting confidential protection of the entire maintenance schedule. The information contained in this response and for which LG&E is seeking confidential protection is identical in nature to that provided to the Commission in response to the Commission's requests for information in Case No. 2000-497 and previously in this proceeding. The Commission granted confidential protection to LG&E's planned maintenance schedule for each of LG&E's generating units. This information would allow competitors to LG&E to know when LG&E's generating plants will be down for maintenance and thus know a crucial input into LG&E's generating costs and need for power and energy during those periods. The commercial risk of the disclosure of this information is that potential suppliers will be able to manipulate the price of power bid to LG&E in order to maximize their revenues.

3. KRS 61.878(1)(c) protects commercial information, generally recognized as confidential or proprietary, if its public disclosure would cause competitive injury to the disclosing entity. Competitive injury occurs when disclosure of the information would give competitors an unfair business advantage. The attached information contains such competitive and proprietary information, and is therefore being submitted with a request for confidential treatment.

4. The information sought to be protected was developed internally by LG&E personnel. The information is not on file with the Federal Energy Regulatory Commission, the Securities and Exchange Commission or other public agencies, and is not available from any

commercial or other source outside of LG&E. Distribution of the information within LG&E is limited to those employees who have a business reason to have access to the information.

5. The information described in Paragraph 2 above is confidential and proprietary information which should not be disclosed in the public record. Disclosure of this information would provide unfair commercial advantages to LG&E's competitors in the wholesale market for bulk and off-system power sales. The passage of the Energy Policy Act has brought extensive competition to the electric wholesale market and introduced numerous new marketers, brokers, and clearinghouses, and many new sources of non-utility generation of power. The change in federal law has caused electric utilities to file nondiscriminatory open-access transmission tariffs and applications for approval of market-based wholesale power rates with the Federal Energy Regulatory Commission. The FERC has authorized utilities, including LG&E, to charge market-based prices for wholesale power transactions and approved open-access transmission services tariffs. See Kentucky Utilities Company, 71 FERC Par. 61,250 (May 31, 1995). All of these regulatory developments and changes in the law have created a robust and competitive wholesale market for bulk and off-system power sales.

6. LG&E's information regarding monthly coincident peak off-system demands, base case and high case off-system demand and energy forecasts, and scheduled outages or retirements of generation capacity constitutes information that is generally recognized as confidential. This information must remain confidential if the wholesale power market is to remain competitive and LG&E is to continue to compete for wholesale sales and purchase wholesale power at competitive prices. Disclosure of this information could provide suppliers with LG&E's expectations about the price of supplies in the future and would allow suppliers to take advantage of LG&E's solicitations by increasing their bids to the maximum extent possible,

thereby causing higher prices for LG&E's customers, and would give commercial advantages to LG&E's competitors.

7. The information provided in response to Item No. 11 of Appendix G to the Commission's December 20, 2001 Order demonstrates on its face that it merits confidential protection. If the Commission disagrees, however, it must hold an evidentiary hearing to protect the due process rights of LG&E and supply the Commission with a complete record to enable it to reach a decision with regard to this matter. Utility Regulatory Commission v. Kentucky Water Service Company, Inc., Ky. App., 642 S.W.2d 591, 592-94 (1982).

8. LG&E does not object to disclosure of the confidential information, pursuant to a protective agreement, to intervenors with a legitimate interest in reviewing the confidential information for the purpose of assisting the Commission's review in this proceeding.

9. In accordance with the provisions of 807 KAR 5:001(7), LG&E is filing with the Commission one (1) set of the confidential information provided in response to Item No. 11 of Appendix G to the Commission's December 20, 2001 Order with the information highlighted and marked confidential and ten (10) sets of the response without the confidential information.

WHEREFORE, Louisville Gas and Electric Company respectfully requests that the Commission grant confidential protection for the information at issue, or schedule an evidentiary hearing on all factual issues while maintaining the confidentiality of the information pending the outcome of the hearing.

Dated: March 1, 2004

Respectfully submitted,

Linda S. Portasik

Linda S. Portasik
Senior Corporate Attorney
LG&E Energy Corporation
220 West Main Street
Louisville, Kentucky 40202

Counsel for Louisville Gas and Electric Company

LOUISVILLE GAS AND ELECTRIC COMPANY

2003 ANNUAL RESOURCE ASSESSMENT FILING
PURSUANT TO APPENDIX G OF THE COMMISSION'S ORDER
DATED DECEMBER 20, 2001 IN ADMINISTRATIVE CASE NO. 387
FILED MARCH 1, 2004

ITEM NO. 11

RESPONDENT: Robert Conroy

11. A list that identifies scheduled outages or retirements of generating capacity during the current year and the following four years.

Response:

The expected maintenance outage schedule for the years 2004 through 2008 is being provided pursuant to a Petition for Confidential Protection. The schedule is regularly modified based on actual operating conditions, forced outages, changes in the schedule in meeting environmental compliance regulations, fluctuations in wholesale prices, and other unforeseen events.

The Companies have retired Green River Units 1 and 2, effective 12/31/2003. Also, KU is presently working with the U.S. Army Corps of Engineers, FERC, and the Kentucky River Authority on the detailed requirements for retirement and license surrender of Lock 7. Lock 7 is expected to be retired in 2005. Additionally, the Companies are reviewing the economic operability of the units contained in the table below. Further discussions on the economic review are contained on page 5-44 of Volume I of the IRP.

Type of Unit	Plant Name	Unit	Summer Capacity	In Service Year	Age (2003)
Steam	Tyrone	1	27	1947	56
Steam	Tyrone	2	31	1948	55
CT	Waterside	7	11	1964	39
CT	Waterside	8	11	1964	39
CT	Cane Run	11	14	1968	35
CT	Paddy's Run	11	12	1968	35
CT	Paddy's Run	12	23	1968	35
CT	Zorn	1	14	1969	34
CT	Haefling	1,2,3	36	1970	33

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

In the Matter of:

A REVIEW OF THE ADEQUACY OF KENTUCKY'S GENERATION CAPACITY AND TRANSMISSION SYSTEM	)))	ADMINISTRATIVE CASE NO. 387

2003 ANNUAL RESOURCE ASSESSMENT FILING
OF
LOUISVILLE GAS AND ELECTRIC COMPANY
PURSUANT TO APPENDIX G
OF THE COMMISSION'S ORDER
DATED DECEMBER 20, 2001

FILED: MARCH 1, 2004

LOUISVILLE GAS AND ELECTRIC COMPANY

2003 ANNUAL RESOURCE ASSESSMENT FILING PURSUANT TO APPENDIX G OF THE COMMISSION'S ORDER DATED DECEMBER 20, 2001 IN ADMINISTRATIVE CASE NO. 387 FILED MARCH 1, 2004

ITEM NO. 1

RESPONDENT: Robert Thomson

1. Actual and weather-normalized energy sales for the just completed calendar year. Sales should be disaggregated into native load sales and off-system sales. Off-system sales should be further disaggregated into full requirements sales, firm capacity sales, and non-firm or economy energy sales. Off-system sales should be further disaggregated to identify separately all sales where the utility acts as a reseller, or transporter, in a power transaction between two or more other parties.

Response:

Please refer to attached Table LGE-1 for actual and weather-normalized billed sales and off-system sales in the requested breakdowns.

TABLE LGE-1

NATIVE AND OFF-SYSTEM SALES BY MONTH: 2003 (MWh's)

LOUISVILLE GAS & ELECTRIC

ACTUAL NATIVE BILLED SALES 2003	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Residential	342,550	333,820	285,439	229,678	251,816	284,019	447,364	440,168	418,422	244,103	233,642	304,782	3,815,803
Small Commercial	104,020	103,319	96,923	90,652	96,977	103,126	126,646	123,790	124,329	95,265	90,950	99,575	1,255,572
Large Commercial	178,603	178,048	171,053	166,778	177,780	184,402	214,882	206,007	209,455	172,364	165,641	178,033	2,203,046
Industrial	241,284	239,728	239,475	242,015	247,232	229,924	251,129	252,555	268,065	238,892	243,605	237,024	2,930,929
Public Authority	93,826	92,969	91,953	84,110	96,694	100,283	112,906	114,150	114,822	91,513	87,164	92,704	1,173,092
Street Lighting	6,911	5,931	5,965	5,319	5,019	4,675	4,902	5,214	5,600	6,188	6,476	7,030	69,229
Total Internal (Native)	967,196	953,816	890,807	818,551	875,519	906,430	1,157,828	1,141,882	1,140,694	848,324	827,477	919,148	11,447,671

WEATHER NORMALIZED NATIVE BILLED SALES	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Residential	347,878	312,330	277,521	238,403	245,591	345,340	476,619	473,232	412,952	272,671	240,956	313,242	3,956,736
Small Commercial	104,677	100,488	95,927	91,394	96,115	113,769	131,311	129,132	123,388	100,881	91,754	100,557	1,279,391
Large Commercial	179,537	175,243	169,850	168,222	176,666	201,260	221,767	213,161	208,177	180,743	166,922	179,016	2,240,563
Industrial	241,284	239,728	239,475	242,015	247,232	229,924	251,129	252,555	268,065	238,892	243,605	237,024	2,930,929
Public Authority	93,910	92,729	91,644	84,558	96,182	103,325	114,015	115,359	114,701	92,121	87,224	92,829	1,178,596
Street Lighting	6,911	5,931	5,965	5,319	5,019	4,675	4,902	5,214	5,600	6,188	6,476	7,030	69,229
Total Internal (Native)	974,198	926,450	880,381	829,910	866,805	998,293	1,199,743	1,188,653	1,132,883	891,496	836,936	929,698	11,655,444

OFF-SYSTEM SALES From Generation	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Firm	178,838	109,392	134,782	114,207	31,645	88,746	87,121	90,071	140,245	183,856	80,832	169,380	1,409,115
Non-Firm	198,699	170,926	286,447	237,780	96,722	158,159	135,020	151,608	205,767	210,577	117,799	177,279	2,146,783
Total	377,537	280,318	421,229	351,987	128,367	246,905	222,141	241,679	346,012	394,433	198,631	346,659	3,555,898
Brokered Sales	83,733	62,508	54,816	41,619	104,115	40,081	6,873	12,431	50,451	77,558	77,474	72,083	683,742
Total Off-System Sales	461,270	342,826	476,045	393,606	232,482	286,986	229,014	254,110	396,463	471,991	276,105	418,742	4,239,640

LOUISVILLE GAS AND ELECTRIC COMPANY

2003 ANNUAL RESOURCE ASSESSMENT FILING PURSUANT TO APPENDIX G OF THE COMMISSION'S ORDER DATED DECEMBER 20, 2001 IN ADMINISTRATIVE CASE NO. 387 FILED MARCH 1, 2004

ITEM NO. 2

RESPONDENT: Nancy Smith

2. A summary of monthly power purchases for the just completed calendar year. Purchases should be disaggregated into firm capacity purchases required to serve native load, economy energy purchases, and purchases where the utility acts as a reseller, or transporter, in a power transaction between two or more other parties.

Response:

A summary of monthly power purchases for 2003, exclusive of any post-period adjustments and disaggregated, as requested, is provided in the attached table.

Table LGE-2
Monthly Power Purchases 2003
Louisville Gas & Electric Company

	2003 MWH		Total Cost	$/MWH
JANUARY				
Firm Capacity Purchases Required to Serve Native Load	80,235	$	2,051,177	$ 25.56
Economy Energy Purchases	3,835	$	165,096	$ 43.05
Company Acts as a Reseller	334,793	$	6,570,761	$ 19.63
Brokered Purchases	84,743	$	3,611,563	$ 42.62
TOTAL	503,606	$	12,398,597	$ 24.62
FEBRUARY				
Firm Capacity Purchases Required to Serve Native Load	79,570	$	2,042,441	$ 25.67
Economy Energy Purchases	393	$	11,150	$ 28.37
Company Acts as a Reseller	243,089	$	4,152,864	$ 17.08
Brokered Purchases	63,075	$	2,315,260	$ 36.71
TOTAL	386,127	$	8,521,714	$ 22.07
MARCH				
Firm Capacity Purchases Required to Serve Native Load	83,678	$	2,096,383	$ 25.05
Economy Energy Purchases	-	$	-	$ -
Company Acts as a Reseller	354,205	$	6,575,354	$ 18.56
Brokered Purchases	55,404	$	2,347,971	$ 42.38
TOTAL	493,287	$	11,019,707	$ 22.34
APRIL				
Firm Capacity Purchases Required to Serve Native Load	74,685	$	1,978,300	$ 26.49
Economy Energy Purchases	-	$	-	$ -
Company Acts as a Reseller	278,246	$	4,653,478	$ 16.72
Brokered Purchases	41,960	$	1,625,027	$ 38.73
TOTAL	394,891	$	8,256,805	$ 20.91
MAY				
Firm Capacity Purchases Required to Serve Native Load	77,982	$	2,074,706	$ 26.60
Economy Energy Purchases	26,077	$	625,534	$ 23.99
Company Acts as a Reseller	101,856	$	1,796,767	$ 17.64
Brokered Purchases	104,989	$	3,624,087	$ 34.52
TOTAL	310,904	$	8,121,093	$ 26.12
JUNE				
Firm Capacity Purchases Required to Serve Native Load	59,404	$	1,836,213	$ 30.91
Economy Energy Purchases	797	$	15,357	$ 19.27
Company Acts as a Reseller	207,673	$	3,502,467	$ 16.87
Brokered Purchases	40,395	$	1,472,185	$ 36.44
TOTAL	308,269	$	6,826,223	$ 22.14
JULY				
Firm Capacity Purchases Required to Serve Native Load	73,452	$	2,016,552	$ 27.45
Economy Energy Purchases	5,799	$	210,832	$ 36.36
Company Acts as a Reseller	189,886	$	3,552,767	$ 18.71
Brokered Purchases	6,957	$	249,122	$ 35.81
TOTAL	276,094	$	6,029,273	$ 21.84
AUGUST				
Firm Capacity Purchases Required to Serve Native Load	82,401	$	2,131,438	$ 25.87
Economy Energy Purchases	1,871	$	55,271	$ 29.54
Company Acts as a Reseller	205,323	$	3,999,659	$ 19.48
Brokered Purchases	12,500	$	595,702	$ 47.66
TOTAL	302,095	$	6,782,070	$ 22.45
SEPTEMBER				
Firm Capacity Purchases Required to Serve Native Load	68,864	$	1,957,668	$ 28.43
Economy Energy Purchases	951	$	23,657	$ 24.88
Company Acts as a Reseller	269,375	$	4,359,195	$ 16.18
Brokered Purchases	50,561	$	1,380,617	$ 27.31
TOTAL	389,751	$	7,721,137	$ 19.81
OCTOBER				
Firm Capacity Purchases Required to Serve Native Load	74,061	$	2,024,375	$ 27.33
Economy Energy Purchases	-	$	-	$ -
Company Acts as a Reseller	312,626	$	5,158,969	$ 16.50
Brokered Purchases	77,679	$	1,897,647	$ 24.43
TOTAL	464,366	$	9,080,992	$ 19.56
NOVEMBER				
Firm Capacity Purchases Required to Serve Native Load	70,722	$	1,981,515	$ 28.02
Economy Energy Purchases	369	$	7,601	$ 20.60
Company Acts as a Reseller	162,586	$	2,852,330	$ 17.54
Brokered Purchases	77,601	$	1,842,905	$ 23.75
TOTAL	311,278	$	6,684,352	$ 21.47
DECEMBER				
Firm Capacity Purchases Required to Serve Native Load	93,202	$	2,270,093	$ 24.36
Economy Energy Purchases	656	$	14,600	$ 22.26
Company Acts as a Reseller	304,646	$	5,572,460	$ 18.29
Brokered Purchases	72,380	$	2,062,506	$ 28.50
TOTAL	470,884	$	9,919,658	$ 21.07
TOTAL				
Firm Capacity Purchases Required to Serve Native Load	918,256	$	24,460,860	$ 26.64
Economy Energy Purchases	40,748	$	1,129,098	$ 27.71
Company Acts as a Reseller	2,964,304	$	52,747,071	$ 17.79
Brokered Purchases	688,244	$	23,024,592	$ 33.45
TOTAL	4,611,552	$	101,361,622	$ 21.98

ITEM NO. 3

RESPONDENT: Bruce Sauer/Robert Conroy

3. Actual and weather-normalized monthly coincident peak demands for the just completed calendar year. Demands should be disaggregated into (a) native load demand (firm and non-firm) and (b) off-system demand (firm and non-firm).

Response:

TABLE LGE-3
NATIVE AND OFF-SYSTEM DEMANDS BY MONTH FOR 2003

Louisville Gas & Electric Co.

	Actual			Normal Weather (Seasonal)	Off-System (2)		
Time of Monthly Native Peak	Native Peak	Non-Firm (1)	Firm	Native Peak	Firm (3)	Non-Firm (3)	Total
2003-01-23-20:00	1,824	50	1,774	1,822	192	214	406
2003-02-10-09:00	1,662	50	1,612		91	142	233
2003-03-10-09:00	1,563	41	1,522		55	117	172
2003-04-30-17:00	1,735	58	1,677		64	132	196
2003-05-09-14:00	1,823	52	1,771		0	0	0
2003-06-25-16:00	2,347	28	2,319		69	122	191
2003-07-08-14:00	2,471	27	2,444		8	13	21
2003-08-27-15:00	2,583	26	2,557	2,612	5	9	14
2003-09-10-16:00	2,051	22	2,029		251	369	620
2003-10-08-16:00	1,538	48	1,490		353	405	758
2003-11-04-19:00	1,573	35	1,538		155	226	381
2003-12-11-19:00	1,682	58	1,624		380	398	778

Notes

(1) Non-firm native load is the amount expected from customers served under the LG&E Interruptible Service Rider.
(2) The allocation of off-system sales split between LG&E and KU is handled in the After-the-Fact Billing process in accordance with the Power Supply System Agreement between LG&E and KU. The individual company sales will include an allocation of the sales sourced with purchased power and allocated to the individual company based on each company's constribution to off-system sales.
(3) The allocation of off-system sales between firm and non-firm is not available from the hourly data in AFB. The breakout is based on the monthly totals for LG&E and KU sales for firm and non-firm sales.

LOUISVILLE GAS AND ELECTRIC COMPANY

2003 ANNUAL RESOURCE ASSESSMENT FILING PURSUANT TO APPENDIX G OF THE COMMISSION'S ORDER DATED DECEMBER 20, 2001 IN ADMINISTRATIVE CASE NO. 387 FILED MARCH 1, 2004

ITEM NO. 4

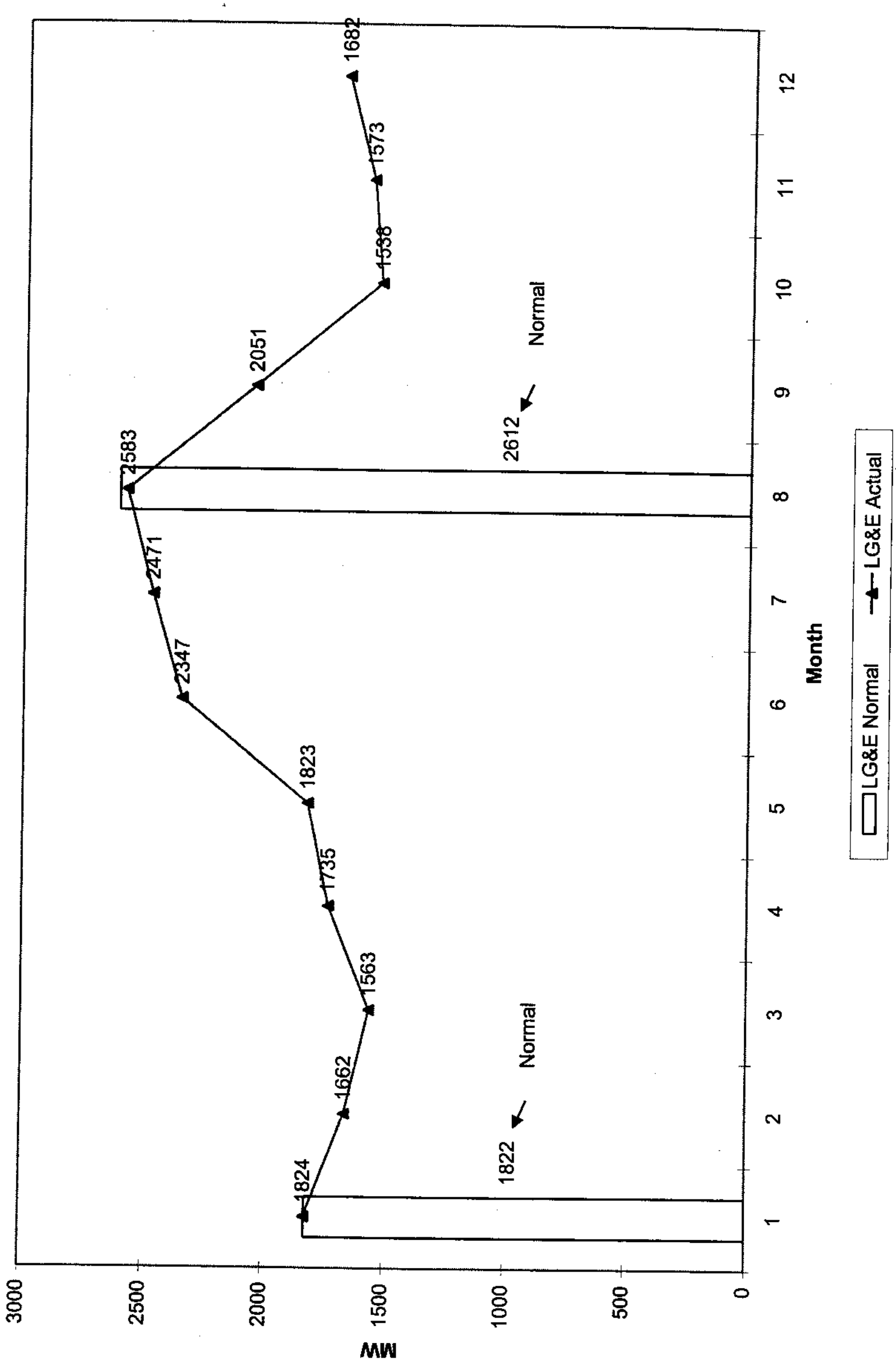
RESPONDENT: Robert Thomson

4. Load shape curves that show actual peak demands and weather-normalized peak demands (native load demand and total demand) on a monthly basis for the just completed calendar year.

Response:

Please refer to attached Figure LGE-4.

Figure LGE-4
Actual and Weather Normalized LG&E Peak Demand for 2003



LOUISVILLE GAS AND ELECTRIC COMPANY

2003 ANNUAL RESOURCE ASSESSMENT FILING PURSUANT TO APPENDIX G OF THE COMMISSION'S ORDER DATED DECEMBER 20, 2001 IN ADMINISTRATIVE CASE NO. 387 FILED MARCH 1, 2004

ITEM NO. 5

RESPONDENT: Robert Conroy

5. Load shape curves showing the number of hours that native load demand exceeded these levels during the just completed calendar year: (1) 70% of the sum of installed generating capacity plus firm capacity purchases; (2) 80% of the sum of installed generating capacity plus firm capacity purchases; (3) 90% of the sum of installed generating capacity plus firm capacity purchases.

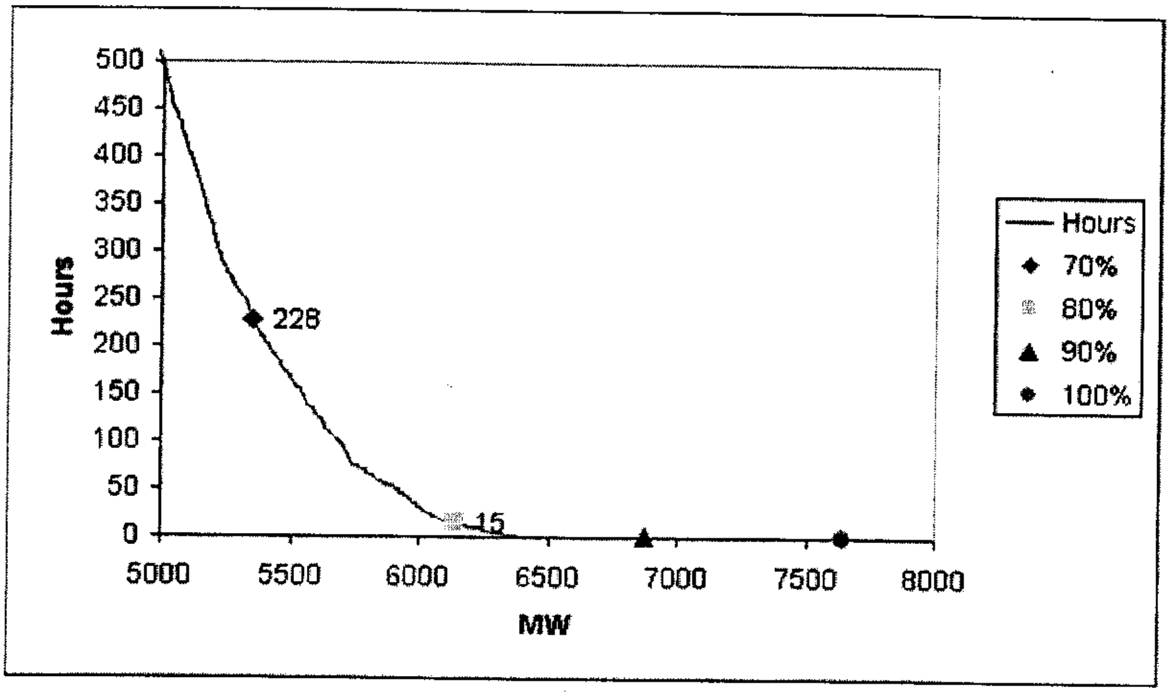
Response:

From a planning perspective LG&E and KU had installed generating capacity of 7,043 MW and firm capacity purchases of 600 MW (total of 7,643 MW) for the summer 2003. The attached graph indicates the number of hours in which actual load was greater than the levels indicated. The table below summarizes this information.

Capacity Level	Number of Hours Load Exceeded
100% - 7,643 MW	0
90% - 6,879 MW	0
80% - 6,114 MW	15
70% - 5,350 MW	228

Figure LGE-5

LG&E/KU Combined Load
Number of Hours Load Exceeded 70%, 80%, and 90% of Installed Generating Capacity Plus Firm Capacity Purchases



LOUISVILLE GAS AND ELECTRIC COMPANY

2003 ANNUAL RESOURCE ASSESSMENT FILING PURSUANT TO APPENDIX G OF THE COMMISSION'S ORDER DATED DECEMBER 20, 2001 IN ADMINISTRATIVE CASE NO. 387 FILED MARCH 1, 2004

ITEM NO. 6

RESPONDENT: Robert Thomson/Robert Conroy

6. Based on the most recent demand forecast, the base case demand and energy forecasts and high case demand and energy forecasts for the current year and the following four years. The information should be disaggregated into (a) native load (firm and non-firm demand) and (b) off-system load (both firm and non-firm demand).

Response:

a) Please see the attached Table LGE-6a.

b) Off-system sales projections for 2004-2008 are contained in Table LGE-6b. For Off-System Sales, only base case total sales energy projections exist for 2004-2008. The projections consist of "Existing OSS", which includes an existing long-term sales agreement with EKPC, and the expected "Wholesale" market sales. In the long-range model, wholesale financially Firm and Non-firm sales are not distinguished but are combined into an overall expected sales energy. However, based on the breakout of firm and non-firm sales identified in response to Item No. 1 for both LG&E and KU, approximately 40% of the total sales energy would be financially Firm, and 60% would be Non-firm.

   The projection is developed in-house using the Henwood Energy Services Inc. PROSYM hourly production cost model, with market prices based on data provided to the LG&E Energy Marketing group from several external parties including utilities, energy marketing entities, and/or brokers.

TABLE LGE-6a

LOUISVILLE GAS & ELECTRIC

BASE CASE

	2004	2005	2006	2007	2008
Energy Sales (MWh)	12,416,741	12,656,751	12,869,824	13,024,162	13,266,429
Native Peak Demand (MW)					
Firm	2,579	2,629	2,673	2,705	2,756
Non-Firm	0	0	0	0	0

Table LGE-6b
Total Base Case Off-System Sales Energy Projection

	2004	2005	2006	2007	2008
Existing OSS (GWH)	312	139	0	0	0
Wholesale OSS (GWH)	3,064	3,003	2,850	2,546	2,557
Total OSS (GWH)	3,377	3,142	2,850	2,546	2,557

LOUISVILLE GAS AND ELECTRIC COMPANY

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ITEM NO. 7

RESPONDENT: Robert Conroy

7. The target reserve margin currently used for planning purposes, stated as a percentage of demand. If changed from what was in use in 2001, include a detailed explanation for the change.

Response:

The Companies established a reserve margin target for 2004 and beyond in the range of 13% to 15%, which provides an optimum level of reliability through various system operating conditions. The reserve margin analysis was performed as part of the 2002 Integrated Resource Plan, filed with the Commission in October 2002 (Case No. 2002-00367). The Companies' expansion plan is based on maintaining a 14% target reserve margin.

The Companies utilized a target reserve margin of 12% in 2001 and 14% in 2002 based on a reserve margin range of 11%-14% established in the Companies' 1999 IRP. A detailed explanation of the change to the current target reserve margin is documented in the report titled "2002 Analysis of Reserve Margin Planning Criterion" contained in Volume III of the Companies' 2002 IRP.

LOUISVILLE GAS AND ELECTRIC COMPANY

2003 ANNUAL RESOURCE ASSESSMENT FILING PURSUANT TO APPENDIX G OF THE COMMISSION'S ORDER DATED DECEMBER 20, 2001 IN ADMINISTRATIVE CASE NO. 387

FILED MARCH 1, 2004

ITEM NO. 8

RESPONDENT: Robert Conroy

8. Projected reserve margins stated in megawatts and as a percentage of demand for the current year and the following 4 years. Identify projected deficits and current plans for addressing these. For each year identify the level of firm capacity purchases projected to meet native load demand.

Response:

The requested reserve margin data is specified in the attached table LGE-8. The capacity in MW required to meet the reserve margin targets of 13% and 15% are also specified in the table. These values represent reserve margins prior to any future resource acquisition. Based on the current load forecast, no deficits are projected over the five-year period.

Table LGE-8
Combined Company
Reserve Margin Needs (MW)

Current Values	2004	2005	2006	2007	2008
Peak Load	6,632	6,796	6,911	7,051	7,225
CSR/Interrupt	-100	-100	-100	-100	-100
New DSM	-44	-67	-89	-108	-116
Net Load	6,488	6,629	6,722	6,843	7,009
Existing Capability	6,975	6,977	6,968	6,970	6,971
EEI	200	200	200	200	200
OMU	193	191	189	186	184
OVEC	209	209	209	209	209
Total Supply	7,577	7,577	7,566	7,565	7,564
MW Margin	1,089	948	844	722	555
Reserve Margin %	16.8%	14.3%	12.6%	10.6%	7.9%
Capacity Need for 13%	(245)	(86)	30	168	356
Capacity Need for 15%	(116)	47	165	304	496
New Capacity	608	0	0	0	0
Total Supply	8,185	8,185	8,174	8,173	8,172
Reserve Margin, MW	1,697	1,556	1,452	1,330	1,163
Reserve Margin %	26.2%	23.5%	21.6%	19.4%	16.6%

Based on 2004 Load forecast.

LOUISVILLE GAS AND ELECTRIC COMPANY

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ITEM NO. 9

RESPONDENT: Robert Conroy

9. By date and hour, identify all incidents during the just completed calendar year when reserve margin was less than the East Central Area Reliability Council's ("ECAR") 1.5% spinning reserve requirement. Include the amount of capacity resources that were available, the actual demand on the system, and the reserve margin, stated in megawatts and as a percentage of demand. Also identify system conditions at the time.

Response:

From a planning perspective, the Companies have secured reserve to maintain a reserve margin above the minimum value of the target reserve margin range in all peak months from January 2003 to the present.

The reserve margin target is a planning criterion, not an operating criterion. The purpose of the reserve margin is to maintain a level of capacity in reserve - capacity that is available should there be an unexpected loss of generation, reduced generation capacity due to equipment problems, unanticipated load growth, variances in load due to extreme weather conditions, and/or disruptions in contracted purchased power. These events are operating events; the reserve margin criterion is a method used to plan for such events, not a standard against which operating conditions are to be measured. In other words, securing a 14% planning reserve margin for the summer peak period does not mean that the Companies will maintain 14% reserve capacity in every hour of actual operation.

In the operating arena, reserve criteria exist that are analogous to the reserve margin target criteria of the planning arena. Operating Reserve is maintained on a real-time basis, to maintain system reliability should any of the operating events listed above occur. The June through December 2003 data is not available from ECAR at this time. Note that the attachments reflect Spinning Reserve only; the Companies maintain other reserves that are not included in the ECAR data. Table LGE-9 highlights those hours during 2003 for which the ECAR report indicates the Companies had insufficient spinning reserve.

FAX

PLEASE DELIVER IMMEDIATELY TO THE PERSON LISTED FOR YOUR COMPANY

TO: **Jason Knoy** **Business Fax: (502) 217-2360**

LGEE

FROM: Sandy Ross - ECAR

DATE: February 25, 2004

6 pages including cover sheet.

Hi Jason,

Please find the Spinning Reserve Reports for January 2003 thru May 2003 attached.
Please contact me if you have any questions.

Thanks,

Sandy Ross
ECAR

PHONE: 330/580-8011
FAX: 330/456-5408

LGEE SPINNING RESERVE REPORT FOR THE MONTH OF JANUARY 2003

DATE		----------- AFTER THE FACT			-----------		
		COMMON HOUR SPINNING			PEAK HOUR SPINNING		
		REQUIRED	ACTUAL		REQUIRED	ACTUAL	
		MW	MW	% RESV	MW	MW	% RESV
Wed	1	0	0	0.0	0	0	0.0
Thu	2	66	595	13.5	66	595	13.5
Fri	3	71	313	6.6	71	313	6.6
Sat	4						
Sun	5						
Mon	6	73	327	6.8	73	327	6.8
Tue	7	71	300	6.3	74	515	10.4
Wed	8	64	315	7.4	69	354	7.7
Thu	9	62	538	13.1	64	656	15.3
Fri	10	70	496	10.7	70	379	8.1
Sat	11						
Sun	12						
Mon	13	70	292	6.3	75	1051	20.9
Tue	14	75	380	7.6	75	256	5.1
Wed	15	74	333	6.7	80	618	11.6
Thu	16	76	-361	-7.1*	76	-361	-7.1*
Fri	17	75	700	14.0	78	105	2.0
Sat	18						
Sun	19						
Mon	20	68	735	16.2	69	692	15.1
Tue	21	73	493	10.1	74	243	4.9
Wed	22	79	338	6.4	80	276	5.2
Thu	23	88	293	5.0	88	333	5.7
Fri	24	79	335	6.3	88	1043	17.8
Sat	25						
Sun	26						
Mon	27	81	588	10.9	88	425	7.2
Tue	28	70	392	8.3	75	357	7.1
Wed	29	71	297	6.3	71	297	6.3
Thu	30	71	278	5.9	72	281	5.8
Fri	31	67	318	7.1	73	283	5.8

NOTE: The After-the-Fact spinning reserve has been adjusted to reflect zero net inadvertent.

* DENOTES LESS THAN 1.5% SPINNING RESERVE

LGEE SPINNING RESERVE REPORT FOR THE MONTH OF FEBRUARY 2003

DATE		----------- AFTER THE FACT -----------					
	COMMON HOUR SPINNING			PEAK HOUR SPINNING			
	REQUIRED	ACTUAL		REQUIRED	ACTUAL		
	MW	MW	% RESV	MW	MW	% RESV	
Sat	1						
Sun	2						
Mon	3	61	244	6.0	62	247	6.0
Tue	4	70	344	7.4	72	315	6.6
Wed	5	70	331	7.1	77	337	6.5
Thu	6	72	334	6.9	72	345	7.1
Fri	7	75	325	6.5	76	545	10.8
Sat	8						
Sun	9						
Mon	10	72	495	10.3	73	398	8.2
Tue	11	68	588	13.1	73	178	3.6
Wed	12	69	581	12.6	73	590	12.1
Thu	13	65	285	6.6	77	281	5.5
Fri	14	66	312	7.0	70	348	7.4
Sat	15						
Sun	16						
Mon	17	68	450	9.9	69	400	8.7
Tue	18	70	315	6.7	72	333	6.9
Wed	19	67	618	13.9	70	278	6.0
Thu	20	65	356	8.3	68	308	6.7
Fri	21	62	800	19.5	66	329	7.5
Sat	22						
Sun	23						
Mon	24	71	359	7.6	73	360	7.4
Tue	25	72	251	5.2	78	324	6.3
Wed	26	72	369	7.7	75	306	6.1
Thu	27	68	263	5.8	73	290	6.0
Fri	28	64	775	18.2	70	324	7.0

NOTE: The After-the-Fact spinning reserve has been adjusted to reflect zero net inadvertent.

* DENOTES LESS THAN 1.5% SPINNING RESERVE

LGEE SPINNING RESERVE REPORT FOR THE MONTH OF MARCH 2003

DATE	AFTER THE FACT					
	COMMON HOUR SPINNING			PEAK HOUR SPINNING		
	REQUIRED	ACTUAL		REQUIRED	ACTUAL	
	MW	MW	% RESV	MW	MW	% RESV
Sat 1						
Sun 2						
Mon 3	61	277	6.8	73	341	7.0
Tue 4	58	351	9.0	70	272	5.9
Wed 5	62	296	7.2	63	182	4.3
Thu 6	68	303	6.7	70	259	5.6
Fri 7	55	860	23.4	70	420	8.9
Sat 8						
Sun 9						
Mon 10	64	268	6.3	73	322	6.6
Tue 11	58	485	12.5	68	352	7.7
Wed 12	56	545	14.5	64	200	4.7
Thu 13	59	256	6.5	61	220	5.4
Fri 14	55	228	6.2	65	245	5.6
Sat 15						
Sun 16						
Mon 17	56	341	9.2	59	267	6.8
Tue 18	56	203	5.4	58	214	5.5
Wed 19	55	384	10.5	57	220	5.8
Thu 20	55	246	6.8	57	217	5.7
Fri 21	53	496	13.9	57	268	7.1
Sat 22						
Sun 23						
Mon 24	54	491	13.7	57	55	1.4*
Tue 25	55	274	7.5	58	214	5.6
Wed 26	54	597	16.5	57	338	8.8
Thu 27	53	431	12.1	58	479	12.5
Fri 28	52	415	11.9	56	244	6.5
Sat 29						
Sun 30						
Mon 31	56	491	13.0	64	303	7.1

NOTE: The After-the-Fact spinning reserve has been adjusted to reflect zero net inadvertent.

* DENOTES LESS THAN 1.5% SPINNING RESERVE

LGEE SPINNING RESERVE REPORT FOR THE MONTH OF APRIL 2003

DATE		AFTER THE FACT				
	COMMON HOUR SPINNING			PEAK HOUR SPINNING		
	REQUIRED	ACTUAL		REQUIRED	ACTUAL	
	MW	MW	% RESV	MW	MW	% RESV
Tue 1	58	362	9.4	63	495	11.8
Wed 2	55	603	16.3	59	151	3.9
Thu 3	0	423	0.0	0	143	0.0
Fri 4	54	765	21.1	59	304	7.8
Sat 5						
Sun 6						
Mon 7	57	591	15.6	59	695	17.6
Tue 8	57	600	15.9	58	330	8.5
Wed 9	65	2069	48.1	65	623	14.5
Thu 10	60	437	10.9	64	367	8.6
Fri 11	56	213	5.7	60	483	12.0
Sat 12						
Sun 13						
Mon 14	58	362	9.4	59	285	7.3
Tue 15	62	258	6.2	62	258	6.2
Wed 16	62	467	11.2	62	405	9.7
Thu 17	58	218	5.6	59	218	5.5
Fri 18	51	325	9.5	54	129	3.6
Sat 19						
Sun 20						
Mon 21	57	235	6.2	57	227	6.0
Tue 22	56	295	7.9	57	229	6.0
Wed 23	55	252	6.8	59	488	12.3
Thu 24	56	285	7.7	57	436	11.4
Fri 25	55	407	11.1	57	278	7.4
Sat 26						
Sun 27						
Mon 28	60	140	3.5	60	339	8.4
Tue 29	64	363	8.5	65	238	5.5
Wed 30	65	115	2.6	68	168	3.7

NOTE: The After-the-Fact spinning reserve has been adjusted to reflect zero net inadvertent.

* DENOTES LESS THAN 1.5% SPINNING RESERVE

LGEE SPINNING RESERVE REPORT FOR THE MONTH OF MAY 2003

DATE		AFTER THE FACT					
		COMMON HOUR SPINNING			PEAK HOUR SPINNING		
		REQUIRED	ACTUAL		REQUIRED	ACTUAL	
		MW	MW	% RESV	MW	MW	% RESV
Thu	1	70	-239	-5.1*	70	-128	-2.7*
Fri	2	59	396	10.0	60	215	5.4
Sat	3						
Sun	4						
Mon	5	0	561	0.0	0	562	0.0
Tue	6	64	386	9.1	65	490	11.2
Wed	7	61	629	15.5	61	559	13.7
Thu	8	68	427	9.4	68	394	8.7
Fri	9	72	172	3.6	72	172	3.6
Sat	10						
Sun	11						
Mon	12	58	223	5.7	59	266	6.8
Tue	13	60	253	6.3	61	140	3.5
Wed	14	63	249	6.0	63	239	5.7
Thu	15	61	378	9.3	61	310	7.6
Fri	16	64	260	6.1	64	305	7.1
Sat	17						
Sun	18						
Mon	19	70	473	10.1	71	316	6.6
Tue	20	64	670	15.6	65	633	14.6
Wed	21	57	1788	47.4	57	1728	45.3
Thu	22	59	643	16.3	59	643	16.3
Fri	23	59	220	5.6	59	220	5.6
Sat	24						
Sun	25						
Mon	26	0	0	0.0	0	0	0.0
Tue	27	61	302	7.5	61	302	7.5
Wed	28	64	255	6.0	64	255	6.0
Thu	29	58	384	9.9	58	234	6.0
Fri	30	61	238	5.9	61	298	7.3
Sat	31						

NOTE: The After-the-Fact spinning reserve has been adjusted to reflect zero net inadvertent.

* DENOTES LESS THAN 1.5% SPINNING RESERVE

Table LGE-9
Summary of ECAR Spinning Reserve Events <1.5% for LG&E/KU

Date	ECAR Reported Spinning Reserve				Gross Generation (MW)	Purchases (MW)	Gross Native Load (MW)	LG&E/KU System Conditions					
								Units On Forced Outage		Units On Maintenance		Available Generation not Synchronized	
	Required MW	Actual MW	Required %	Actual %				Units	MW	Units	MW	Units	MW
1/16/2003	76	-361	1.5%	-7.1%	5200	516	4553	Green River 3	75	Mill Creek 1	330	Brown 5-8, Brown 10-11, Cane Run 11, Haefling 1-3, Paddys Run 11-13, Trimble County 5-6, Tyrone 1-2, Waterside 7-8, Zorn 1	1646
3/24/2003	57	55	1.5%	1.4%	4391	554	3412	Brown 3[1], Ohio Falls	64	Ghent 3, Green River 3, Green River 1-2, Green River 4, Tyrone 3, Cane Run 5, Mill Creek 2	1347	Brown 5-11, Cane Run 11, Green River 1-2, Haefling 1-3, Paddys Run 11-13, Trimble County 5-6, Tyrone 1-2, Waterside 7-8, Zorn 1	1787
5/1/2003	70	-128	1.5%	-2.7%	4247	728	4200	Ghent 3, Mill Creek 3[2], Mill Creek 4[3], Brown 5	731	Ghent 1, Green River 4, Tyrone 3, Mill Creek 2, Trimble County 1	1437	Brown 5, Brown 8-11, Cane Run 11, Green River 1-2, Haefling 1-3, Paddys 11-12, Tyrone 1-2, Waterside 7-8, Zorn 1	777

1 - Brown 3 derated 32 MW, not entirely forced out
2 - Mill Creek 3 derated 18 MW, not entirely forced out
3 - Mill Creek 4 derated 68 MW, not entirely forced out

LOUISVILLE GAS AND ELECTRIC COMPANY

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ITEM NO. 10

RESPONDENT: Robert Conroy

10. A list identifying and describing all forced outages in excess of 2 hours in duration during the just completed calendar year.

Response:

A list of all requested outages is included in the attached Table LGE-10.

LGE jointly owned units on KU sites are referenced in KU's Response to Item No. 10.

TABLE LGE-10
LOUISVILLE GAS AND ELECTRIC COMPANY
POWER GENERATION
FORCED OUTAGES GREATER THAN TWO HOURS
2003

Unit	Outage Start/End Dates	Outage Event Description	Duration Hours	Duration Minutes
Cane Run 4	02/17 - 02/17	FEEDWATER VALVES	3	30
	02/20 - 02/21	CONDENSER TUBE AND WATER BOX CLEANING	20	26
	07/10 - 07/11	ECONOMIZER LEAKS	32	14
	08/19 - 08/19	FORCED DRAFT FAN CONTROLS	2	4
	09/11 - 09/11	TURBINE REHEAT/INTERCEPT VALVE TESTING	2	9
	11/07 - 11/07	BURNER MANAGEMENT SYSTEM	2	31
	12/04 - 12/07	FURNACE WALL LEAKS	66	18
Cane Run 5	04/13 - 04/14	INSTRUMENT AND CONTROL PROBLEMS	12	27
	07/12 - 07/12	GENERATOR LIQUID COOLING SYSTEM	2	5
	12/14 - 12/14	CONDENSATE SYSTEM CONTROLS AND INSTRUMENTATION	2	30
	12/28 - 12/28	TURBINE SUPERVISORY SYSTEM	3	24
Cane Run 6	01/13 - 01/15	FURNACE WALL LEAKS	47	23
	01/20 - 01/21	CONDENSER TUBE LEAKS	5	19
	01/24 - 01/24	FORCED DRAFT FAN CONTROLS	3	20
	02/09 - 02/10	CONDENSER CASING AND INTERNAL PROBLEMS	16	44
	05/06 - 05/06	DEAERATOR	4	32
	06/17 - 06/19	DEAERATOR	36	24
	07/08 - 07/10	FURNACE WALL LEAKS	56	18
	08/18 - 08/20	FURNACE WALL LEAKS	46	28
	11/06 - 11/06	CONDENSER TUBE LEAKS	9	46
Cane Run 11	01/24 - 01/24	SERVICE AIR PIPING	10	25
	06/18 - 06/20	GT CONTROLS AND INSTRUMENTS	41	54
	09/05 - 09/05	GT BATTERY AND CHARGER SYSTEM	10	10
	09/10 - 09/12	GT BATTERY AND CHARGER SYSTEM	54	30
	09/12 - 10/03	GT STARTING SYSTEM	503	30
	10/28 - 10/29	INSTRUMENT AND COMPRESSORS	14	53
	10/30 - 10/31	INSTRUMENT AND COMPRESSORS	24	58
	11/12 - 11/12	12 KV PROTECTION DEVICES	3	50
	11/17 - 11/19	GT STARTING SYSTEM	47	30
	11/19 - 11/21	GT CONTROLS AND INSTRUMENTS	53	0
	11/25 - 11/26	GENERATOR AND SYNCHRONIZATION EQUIPMENT	20	5
Mill Creek 1	04/05 - 04/05	CONDENSER VACUUM PUMP PIPING AND VALVES	4	18
	08/10 - 08/10	BOILER RECIRCULATION PIPING	7	55
	09/19 - 09/19	TURBINE CONTROL VALVES	3	46
	09/22 - 09/22	VOLTAGE CONDUCTORS AND BUSES	17	53
	09/29 - 09/29	TURBINE CONTROL VALVES	10	14
	10/22 - 10/23	TURBINE CONTROL VALVES	4	47
	12/30 - 12/31	FURNACE WALL LEAKS	25	12
Mill Creek 2	01/18 - 01/18	CONDENSER TUBE LEAKS	23	38
	01/23 - 01/24	FURNACE WALL LEAKS	17	38
	01/24 - 01/25	FURNACE WALL LEAKS	16	27
	05/14 - 05/17	GENERATOR STATOR WINDINGS, BUSHINGS AND TERMINALS	70	36
	05/24 - 05/25	FURNACE WALL LEAKS	28	19
	06/11 - 06/13	FURNACE WALL LEAKS	45	39
	09/05 - 09/06	CONDENSATE/HOTWELL PUMPS	22	43
	11/09 - 11/09	EXCITER PROBLEMS	5	34
	12/14 - 12/16	FURNACE WALL LEAKS	48	26
	12/28 - 12/29	SCRUBBER RECYCLE PUMPS	44	3
Mill Creek 3	01/17 - 01/17	INSTRUMENT AIR VALVES	4	20
	01/28 - 01/28	FORCED DRAFT FAN MOTORS	5	47
	06/24 - 06/24	TURBINE OVERSPEED TRIP TEST	5	24
	07/12 - 07/12	BOILER DRUMS AND DRUM INTERNALS	2	59
	10/07 - 10/08	ECONOMIZER LEAKS	25	53
	10/21 - 10/23	FIRST REHEATER LEAKS	42	1

TABLE LGE-10
LOUISVILLE GAS AND ELECTRIC COMPANY
POWER GENERATION
FORCED OUTAGES GREATER THAN TWO HOURS
2003

Unit	Outage Start/End Dates	Outage Event Description	Duration Hours	Duration Minutes
Mill Creek 3	11/19 - 11/21	FIRST REHEATER LEAKS	54	56
	11/23 - 11/24	FIRST REHEATER LEAKS	27	42
	12/01 - 12/01	TURBINE LUBE OIL PUMPS	2	3
	12/05 - 12/07	FIRST REHEATER LEAKS	29	42
	12/19 - 12/20	TURBINE INSTRUMENT AND CONTROL PROBLEMS	18	15
	12/20 - 12/20	TURBINE INSTRUMENT AND CONTROL PROBLEMS	2	4
	12/20 - 12/20	TURBINE INSTRUMENT AND CONTROL PROBLEMS	7	43
	12/22 - 12/24	FURNACE WALL LEAKS	38	55
Mill Creek 4	01/17 - 01/17	INSTRUMENT AIR VALVES	6	25
	02/05 - 02/06	SECOND SUPERHEATER LEAKS	41	18
	02/20 - 02/26	SECOND SUPERHEATER LEAKS	137	39
	05/01 - 05/03	SECOND SUPERHEATER LEAKS	47	0
	06/15 - 06/16	FEEDWATER PUMP DRIVE - CONTROLS	2	28
	07/15 - 07/19	SECOND SUPERHEATER LEAKS	94	15
	07/23 - 07/25	LIGHTNING	36	29
	08/08 - 08/09	CONDENSER TUBE LEAKS	23	32
	08/12 - 08/14	CONDENSER CASING AND INTERNAL PROBLEMS	43	20
	09/22 - 09/22	SCRUBBER REACTION TANKS INCLUDING AGITATORS	8	23
	09/29 - 09/30	SECOND SUPERHEATER LEAKS	29	30
	11/26 - 11/26	IP TURBINE BEARINGS	5	15
Ohio Falls 1	01/01 - 01/10	INTAKE CHANNEL OR FLUME (INCLUDING TRASH RACKS)	222	11
	01/24 - 02/03	LACK OF WATER	245	52
	02/08 - 02/10	TURBINE GOVERNOR	56	20
	02/15 - 02/15	INTAKE CHANNEL OR FLUME (INCLUDING TRASH RACKS)	2	15
	02/16 - 02/17	INTAKE CHANNEL OR FLUME (INCLUDING TRASH RACKS)	28	10
	02/17 - 03/14	FLOOD	595	10
	03/14 - 03/25	INTAKE CHANNEL OR FLUME (INCLUDING TRASH RACKS)	255	50
	04/09 - 04/10	INTAKE CHANNEL OR FLUME (INCLUDING TRASH RACKS)	24	34
	04/10 - 04/18	FLOOD	192	38
	05/05 - 05/27	INTAKE CHANNEL OR FLUME (INCLUDING TRASH RACKS)	518	39
	07/11 - 07/16	INTAKE CHANNEL OR FLUME (INCLUDING TRASH RACKS)	120	54
	07/18 - 07/18	INTAKE CHANNEL OR FLUME (INCLUDING TRASH RACKS)	3	24
	08/09 - 08/09	INTAKE CHANNEL OR FLUME (INCLUDING TRASH RACKS)	3	38
	08/19 - 08/20	INTAKE CHANNEL OR FLUME (INCLUDING TRASH RACKS)	14	22
	08/22 - 08/23	PROTECTION DEVICES	9	24
	09/02 - 09/09	INTAKE CHANNEL OR FLUME (INCLUDING TRASH RACKS)	175	12
	09/09 - 09/19	PROTECTION DEVICES	230	53
	09/24 - 09/24	INTAKE CHANNEL OR FLUME (INCLUDING TRASH RACKS)	3	22
	11/01 - 11/01	INTAKE CHANNEL OR FLUME (INCLUDING TRASH RACKS)	6	0
	11/13 - 11/15	INTAKE CHANNEL OR FLUME (INCLUDING TRASH RACKS)	40	15
	11/15 - 11/19	FLOOD	98	50
Ohio Falls 2	01/01 - 01/10	INTAKE CHANNEL OR FLUME (INCLUDING TRASH RACKS)	220	30
	01/27 - 01/29	LACK OF WATER	42	12
	02/07 - 02/11	INTAKE CHANNEL OR FLUME (INCLUDING TRASH RACKS)	98	23
	02/16 - 02/17	INTAKE CHANNEL OR FLUME (INCLUDING TRASH RACKS)	28	7
	02/17 - 03/14	FLOOD	595	10
	03/14 - 03/27	INTAKE CHANNEL OR FLUME (INCLUDING TRASH RACKS)	308	10
	04/09 - 04/10	INTAKE CHANNEL OR FLUME (INCLUDING TRASH RACKS)	23	30
	04/10 - 04/18	FLOOD	191	28
	05/05 - 05/27	INTAKE CHANNEL OR FLUME (INCLUDING TRASH RACKS)	518	33
	06/25 - 06/27	EXCITER DRIVE MOTOR	50	30
	07/11 - 07/16	INTAKE CHANNEL OR FLUME (INCLUDING TRASH RACKS)	122	53
	07/19 - 07/19	INTAKE CHANNEL OR FLUME (INCLUDING TRASH RACKS)	5	19
	08/05 - 08/05	INTAKE CHANNEL OR FLUME (INCLUDING TRASH RACKS)	2	12
	08/19 - 08/20	INTAKE CHANNEL OR FLUME (INCLUDING TRASH RACKS)	16	17
	08/30 - 09/09	PROTECTION DEVICES	249	7
	09/24 - 09/24	INTAKE CHANNEL OR FLUME (INCLUDING TRASH RACKS)	2	34

TABLE LGE-10
LOUISVILLE GAS AND ELECTRIC COMPANY
POWER GENERATION
FORCED OUTAGES GREATER THAN TWO HOURS
2003

Unit	Outage Start/End Dates	Outage Event Description	Duration Hours	Duration Minutes
Ohio Falls 2	11/13 - 11/15	INTAKE CHANNEL OR FLUME (INCLUDING TRASH RACKS)	40	15
	11/15 - 11/19	FLOOD	99	30
	12/23 - 12/31	INTAKE CHANNEL OR FLUME (INCLUDING TRASH RACKS)	201	20
Ohio Falls 3	01/01 - 01/10	INTAKE CHANNEL OR FLUME (INCLUDING TRASH RACKS)	218	5
	01/18 - 01/18	LACK OF WATER	5	2
	02/16 - 02/17	INTAKE CHANNEL OR FLUME (INCLUDING TRASH RACKS)	28	3
	02/17 - 03/14	FLOOD	595	10
	03/14 - 03/27	INTAKE CHANNEL OR FLUME (INCLUDING TRASH RACKS)	307	30
	04/09 - 04/10	INTAKE CHANNEL OR FLUME (INCLUDING TRASH RACKS)	23	28
	04/10 - 04/18	FLOOD	191	12
	05/05 - 05/27	INTAKE CHANNEL OR FLUME (INCLUDING TRASH RACKS)	518	10
	07/11 - 07/15	INTAKE CHANNEL OR FLUME (INCLUDING TRASH RACKS)	102	57
	08/01 - 08/01	INTAKE CHANNEL OR FLUME (INCLUDING TRASH RACKS)	2	2
	08/01 - 08/04	GENERATOR METERING DEVICES	69	57
	08/09 - 08/09	INTAKE CHANNEL OR FLUME (INCLUDING TRASH RACKS)	2	56
	08/09 - 08/11	GENERATOR METERING DEVICES	43	34
	08/19 - 08/20	INTAKE CHANNEL OR FLUME (INCLUDING TRASH RACKS)	14	41
	08/23 - 08/23	INTAKE CHANNEL OR FLUME (INCLUDING TRASH RACKS)	2	45
	08/30 - 09/09	PROTECTION DEVICES	248	51
	12/13 - 12/23	EMERGENCY GENERATOR TRIP DEVICES	229	11
	12/25 - 12/31	INTAKE CHANNEL OR FLUME (INCLUDING TRASH RACKS)	154	20
Ohio Falls 4	01/01 - 01/13	INTAKE CHANNEL OR FLUME (INCLUDING TRASH RACKS)	289	43
	01/18 - 01/18	LACK OF WATER	5	28
	02/15 - 02/15	INTAKE CHANNEL OR FLUME (INCLUDING TRASH RACKS)	4	0
	02/16 - 02/17	INTAKE CHANNEL OR FLUME (INCLUDING TRASH RACKS)	28	0
	02/17 - 03/14	FLOOD	595	10
	03/14 - 03/27	INTAKE CHANNEL OR FLUME (INCLUDING TRASH RACKS)	307	18
	04/09 - 04/10	INTAKE CHANNEL OR FLUME (INCLUDING TRASH RACKS)	23	55
	04/10 - 04/18	FLOOD	190	41
	05/05 - 05/27	INTAKE CHANNEL OR FLUME (INCLUDING TRASH RACKS)	518	3
	07/11 - 07/15	INTAKE CHANNEL OR FLUME (INCLUDING TRASH RACKS)	101	42
	08/05 - 08/05	INTAKE CHANNEL OR FLUME (INCLUDING TRASH RACKS)	3	1
	08/19 - 08/20	INTAKE CHANNEL OR FLUME (INCLUDING TRASH RACKS)	16	37
	08/25 - 08/27	LACK OF WATER	46	59
	09/02 - 09/09	INTAKE CHANNEL OR FLUME (INCLUDING TRASH RACKS)	172	18
	09/12 - 09/13	SERVICE WATER PIPING	20	53
	12/13 - 12/22	EMERGENCY GENERATOR TRIP DEVICES	208	6
	12/22 - 12/31	EMERGENCY GENERATOR TRIP DEVICES	223	34
Ohio Falls 5	01/01 - 01/13	INTAKE CHANNEL OR FLUME (INCLUDING TRASH RACKS)	215	21
	01/29 - 01/29	EMERGENCY GENERATOR TRIP DEVICES	6	49
	02/07 - 02/07	TURBINE BEARING COOLING SYSTEM	2	43
	02/16 - 02/17	INTAKE CHANNEL OR FLUME (INCLUDING TRASH RACKS)	27	57
	02/17 - 03/14	FLOOD	595	10
	03/14 - 03/26	INTAKE CHANNEL OR FLUME (INCLUDING TRASH RACKS)	286	25
	04/10 - 04/18	FLOOD	190	5
	05/05 - 05/05	INTAKE TUNNEL	4	15
	05/05 - 05/27	INTAKE CHANNEL OR FLUME (INCLUDING TRASH RACKS)	522	41
	07/02 - 07/03	LACK OF WATER	16	55
	07/11 - 08/23	INTAKE CHANNEL OR FLUME (INCLUDING TRASH RACKS)	1031	19
	08/30 - 09/09	EMERGENCY GENERATOR TRIP DEVICES	248	50
	10/11 - 10/11	INTAKE CHANNEL OR FLUME (INCLUDING TRASH RACKS)	3	10
	12/14 - 12/15	INTAKE CHANNEL OR FLUME (INCLUDING TRASH RACKS)	26	40
Ohio Falls 6	01/01 - 05/28	WICKET GATE ASSEMBLY	3537	30
	07/11 - 07/15	INTAKE CHANNEL OR FLUME (INCLUDING TRASH RACKS)	95	25
	08/19 - 08/20	INTAKE CHANNEL OR FLUME (INCLUDING TRASH RACKS)	17	15
	08/23 - 08/23	INTAKE CHANNEL OR FLUME (INCLUDING TRASH RACKS)	2	7

TABLE LGE-10
LOUISVILLE GAS AND ELECTRIC COMPANY
POWER GENERATION
FORCED OUTAGES GREATER THAN TWO HOURS
2003

Unit	Outage Start/End Dates	Outage Event Description	Duration Hours	Duration Minutes
Ohio Falls 6	09/02 - 09/09	INTAKE CHANNEL OR FLUME (INCLUDING TRASH RACKS)	169	7
	12/14 - 12/22	INTAKE CHANNEL OR FLUME (INCLUDING TRASH RACKS)	196	47
	12/28 - 12/31	INTAKE CHANNEL OR FLUME (INCLUDING TRASH RACKS)	73	25
Ohio Falls 7	01/01 - 01/10	INTAKE CHANNEL OR FLUME (INCLUDING TRASH RACKS)	215	15
	02/16 - 02/17	INTAKE CHANNEL OR FLUME (INCLUDING TRASH RACKS)	27	53
	02/17 - 03/14	FLOOD	595	23
	03/17 - 03/26	INTAKE CHANNEL OR FLUME (INCLUDING TRASH RACKS)	213	44
	04/10 - 04/18	FLOOD	189	45
	04/20 - 04/20	GENERATOR STATOR WINDINGS, BUSHINGS AND TERMINALS	8	49
	04/20 - 04/21	GENERATOR STATOR WINDINGS, BUSHINGS AND TERMINALS	21	37
	04/21 - 04/22	GENERATOR STATOR WINDINGS, BUSHINGS AND TERMINALS	20	15
	05/05 - 05/27	INTAKE CHANNEL OR FLUME (INCLUDING TRASH RACKS)	517	36
	06/07 - 06/25	FLOOD	422	50
	06/25 - 07/07	GENERATOR LIQUID COOLING SYSTEM	293	18
	07/11 - 07/15	INTAKE CHANNEL OR FLUME (INCLUDING TRASH RACKS)	94	58
	07/23 - 12/31	TURBINE BEARINGS	3879	2
Ohio Falls 8	01/01 - 01/14	GENERATOR METERING DEVICES	320	52
	01/22 - 01/22	LACK OF WATER	8	40
	01/23 - 01/25	LACK OF WATER	39	28
	01/27 - 01/29	LACK OF WATER	38	58
	02/14 - 02/14	INTAKE CHANNEL OR FLUME (INCLUDING TRASH RACKS)	2	28
	02/16 - 02/17	INTAKE CHANNEL OR FLUME (INCLUDING TRASH RACKS)	27	50
	02/17 - 03/14	FLOOD	595	10
	03/17 - 03/26	INTAKE CHANNEL OR FLUME (INCLUDING TRASH RACKS)	213	31
	04/10 - 04/18	FLOOD	189	28
	05/05 - 05/27	INTAKE CHANNEL OR FLUME (INCLUDING TRASH RACKS)	517	14
	06/07 - 06/25	FLOOD	422	47
	06/25 - 07/08	GENERATOR LIQUID COOLING SYSTEM	316	38
	07/11 - 07/15	INTAKE CHANNEL OR FLUME (INCLUDING TRASH RACKS)	94	11
	08/01 - 08/01	INTAKE CHANNEL OR FLUME (INCLUDING TRASH RACKS)	2	28
	09/02 - 09/09	INTAKE CHANNEL OR FLUME (INCLUDING TRASH RACKS)	167	50
	12/23 - 12/31	INTAKE CHANNEL OR FLUME (INCLUDING TRASH RACKS)	204	0
Paddys Run 11	07/01 - 07/08	INSTRUMENT AIR COMPRESSORS	167	0
	08/29 - 09/03	INSTRUMENT AIR COMPRESSORS	128	0
	09/19 - 09/24	GT GAS FUEL SYSTEM	117	25
	10/23 - 10/24	OTHER VOLTAGE CIRCUIT BREAKERS	26	5
Paddys Run 13	01/14 - 01/15	COMPRESSOR HIGH PRESSURE BEARINGS	11	31
	01/17 - 01/17	GENERATOR LIQUID COOLING SYSTEM	6	25
	01/17 - 01/20	GENERATOR LIQUID COOLING SYSTEM	61	24
	07/16 - 07/16	SOLID STATE EXCITER ELEMENT	3	15
	07/18 - 07/18	FIRE PROTECTION SYSTEM PROBLEMS	8	30
	07/26 - 07/27	480-VOLT CONDUCTORS AND BUSES	29	35
	08/08 - 08/09	GT CONTROLS AND INSTRUMENTS	16	15
	08/18 - 08/19	PROTECTION DEVICES	27	35
	08/27 - 08/28	GT CONTROLS AND INSTRUMENTS	13	0
	12/10 - 12/11	GT COMPUTER	11	20
Trimble County 1	01/02 - 01/04	BOILER SCREEN, WING WALL, OR SLAG SCREENLEAKS (WATER TUBES)	25	17
	01/21 - 01/21	PROCESS COMPUTER	3	42
	04/10 - 04/12	ECONOMIZER LEAKS	57	18
	04/21 - 04/24	SECOND SUPERHEATER LEAKS	62	4
	06/03 - 06/03	INDUCED DRAFT FAN MOTORS - VARIABLE SPEED	3	53
	06/11 - 06/11	INDUCED DRAFT FAN MOTORS - VARIABLE SPEED	11	0
	06/28 - 06/28	INDUCED DRAFT FANS	5	43
	07/01 - 07/01	INDUCED DRAFT FAN MOTORS - VARIABLE SPEED	9	19
	07/09 - 07/10	INDUCED DRAFT FAN CONTROLS	8	18

TABLE LGE-10
LOUISVILLE GAS AND ELECTRIC COMPANY
POWER GENERATION
FORCED OUTAGES GREATER THAN TWO HOURS
2003

Unit	Outage Start/End Dates	Outage Event Description	Duration Hours	Duration Minutes
Trimble County 1	07/26 - 07/26	FLUE GAS PROBLEMS	5	38
	12/21 - 12/23	ECONOMIZER LEAKS	33	33
Trimble County 5	01/23 - 01/23	GAS TURBINE EXHAUST PROBLEMS	4	0
	01/23 - 01/26	GT CONTROLS AND INSTRUMENTS	68	42
	01/26 - 01/28	GT CONTROLS AND INSTRUMENTS	47	35
	02/06 - 02/06	GT FUEL PIPING AND VALVES	2	4
	02/06 - 02/06	GT FUEL PIPING AND VALVES	9	33
	02/06 - 02/13	GT FUEL PIPING AND VALVES	159	1
	02/26 - 02/26	GT COMPRESS OR BLEED VALVES	11	10
	04/07 - 04/08	GENERATOR OUTPUT BREAKER	18	45
	04/23 - 04/24	GAS TURBINE EXHAUST PROBLEMS	15	27
	04/24 - 04/24	GAS TURBINE EXHAUST PROBLEMS	3	30
	07/10 - 07/10	LIGHTNING	3	17
	08/03 - 08/04	480-VOLT TRANSFORMERS	18	30
	08/27 - 08/27	GAS TURBINE EXHAUST PROBLEMS	2	13
	09/12 - 09/12	GT FUEL PIPING AND VALVES	2	45
	11/18 - 11/20	CONTRACTOR ERROR	57	10
Trimble County 6	01/23 - 01/23	GAS TURBINE FUEL SYSTEM PROBLEMS	4	0
	01/23 - 01/26	GT CONTROLS AND INSTRUMENTS	67	56
	01/26 - 01/26	GT CONTROLS AND INSTRUMENTS	3	34
	04/07 - 04/07	GAS TURBINE EXHAUST PROBLEMS	4	7.8
	06/17 - 06/17	GT FUEL PIPING AND VALVES	2	30
	07/10 - 07/10	GT FUEL PIPING AND VALVES	8	3
	08/03 - 08/04	480-VOLT TRANSFORMERS	18	30
	09/12 - 09/12	GT FUEL PIPING AND VALVES	2	45
	11/18 - 11/20	CONTRACTOR ERROR	57	10

LOUISVILLE GAS AND ELECTRIC COMPANY

2003 ANNUAL RESOURCE ASSESSMENT FILING
PURSUANT TO APPENDIX G OF THE COMMISSION'S ORDER
DATED DECEMBER 20, 2001 IN ADMINISTRATIVE CASE NO. 387
FILED MARCH 1, 2004

ITEM NO. 11

RESPONDENT: Robert Conroy

11. A list that identifies scheduled outages or retirements of generating capacity during the current year and the following four years.

Response:

The expected maintenance outage schedule for the years 2004 through 2008 is being provided pursuant to a Petition for Confidential Protection. The schedule is regularly modified based on actual operating conditions, forced outages, changes in the schedule in meeting environmental compliance regulations, fluctuations in wholesale prices, and other unforeseen events.

The Companies have retired Green River Units 1 and 2, effective 12/31/2003. Also, KU is presently working with the U.S. Army Corps of Engineers, FERC, and the Kentucky River Authority on the detailed requirements for retirement and license surrender of Lock 7. Lock 7 is expected to be retired in 2005. Additionally, the Companies are reviewing the economic operability of the units contained in the table below. Further discussions on the economic review are contained on page 5-44 of Volume I of the IRP.

Type of Unit	Plant Name	Unit	Summer Capacity	In Service Year	Age (2003)
Steam	Tyrone	1	27	1947	56
Steam	Tyrone	2	31	1948	55
CT	Waterside	7	11	1964	39
CT	Waterside	8	11	1964	39
CT	Cane Run	11	14	1968	35
CT	Paddy's Run	11	12	1968	35
CT	Paddy's Run	12	23	1968	35
CT	Zorn	1	14	1969	34
CT	Haefling	1,2,3	36	1970	33

LOUISVILLE GAS AND ELECTRIC COMPANY

2003 ANNUAL RESOURCE ASSESSMENT FILING PURSUANT TO APPENDIX G OF THE COMMISSION'S ORDER DATED DECEMBER 20, 2001 IN ADMINISTRATIVE CASE NO. 387 FILED MARCH 1, 2004

ITEM NO. 12

RESPONDENT: Robert Conroy

12. Identify all planned base load or peaking capacity additions to meet native load requirements over the next 10 years. Show the expected in-service date, size and site for all planned additions. Include additions planned by the utility, as well as those by affiliates, if constructed in Kentucky or intended to meet load in Kentucky.

Response:

The Companies were granted a Certificate of Public Convenience and Necessity for the Acquisition of the Four Combustion Turbines on March 18, 2003 (Case No. 2002-00381). The combustion turbines will be available for operation by the summer of 2004. The Companies are currently evaluating the baseload need identified in the 2002 IRP. The table below contains MW needs to maintain a 14% reserve margin through 2013 based on the most recent load forecast.

The Companies are not aware of any planned additions by utility affiliates to be constructed in Kentucky to meet load in Kentucky. However, the Companies and the utility affiliates continually review and study possible base load and/or peaking capacity additions.

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
MW Need	(789)	(628)	(511)	(372)	(182)	(14)	114	312	430	658

LOUISVILLE GAS AND ELECTRIC COMPANY

2003 ANNUAL RESOURCE ASSESSMENT FILING PURSUANT TO APPENDIX G OF THE COMMISSION'S ORDER DATED DECEMBER 20, 2001 IN ADMINISTRATIVE CASE NO. 387 FILED MARCH 1, 2004

ITEM NO. 13

RESPONDENT: Mark Johnson

13. The following transmission energy data for the just completed calendar year and the forecast for the current year and the following four years:

a. Total energy received from all interconnections and generation sources connected to the transmission system.

b. Total energy delivered to all interconnections on the transmission system.

c. Peak load capacity of the transmission system.

d. Peak demand for summer and winter seasons on the transmission system.

Response:

Data exists for 2003. No forecasts exist for 2003-2008.

a. LG&E and KU are operated as one NERC Control Area, statistics below are total sources for the single Control Area:

Tie Lines Received (GWH)	13,467,467
Net Generation LG&E (GWH)	12,172,559
Net Generation KU (GWH)	20,700,072
Total Sources (GWH)	46,340,098

b. LG&E and KU are operated as one NERC Control Area, the amount of energy delivered at the interconnections of the single Control Area was 15,086,376 GWH(s).

c. There is no set number for peak load capacity for the transmission system. The system is built to support native load under first contingency conditions. Actual transmission capacity available for native load, import, export or thru-flow will vary depending on which facilities in the Transmission System of the Eastern Interconnect are in service.

d. The maximum summer peak transmission load for the common Control Area was 6573 MW for the peak hour of August 27, 2003, with 3979 MW of load on the KU transmission facilities and 2594 on the LG&E transmission facilities.

   The maximum winter peak transmission load for the common Control Area was 6107 MW for the peak hour of January 23, 2003, with 4273 MW of load on the KU transmission facilities and 1834 on the LG&E transmission facilities.

LOUISVILLE GAS AND ELECTRIC COMPANY

2003 ANNUAL RESOURCE ASSESSMENT FILING
PURSUANT TO APPENDIX G OF THE COMMISSION'S ORDER
DATED DECEMBER 20, 2001 IN ADMINISTRATIVE CASE NO. 387
FILED MARCH 1, 2004

ITEM NO. 14

RESPONDENT: Mark Johnson

14. Identify all planned transmission capacity additions for the next 10 years. Include the expected in-service date, size and site for all planned additions and identify the transmission need each addition is intended to address.

Response:

The Midwest ISO's 10 year expansion plan, dated 12/4/03, is attached for the planned and proposed projects on the LG&E and KU Transmission System for facilities greater than 100 KV. In addition the exhibit attached contains an explanation of need for the planned and proposed projects for all voltage levels.

'04/03

Form 1 of 2 for Reporting Lines and Transformers In the Baseline Reliability Study (MTEP-04)

Note #1: PLANNED projects are the preferred solution to an identified issue. PROPOSED projects are a tentative solution to an identified issue.

Note #2: The projects in this list are projected for service on the date indicated. They are expected to be needed to meet existing committments including network and native load growth. Becuase there is always the possibility of delay in permitting and construction, or for modification or deferral of projects as system conditions change, Transmission Providers should not assume that these projects are In Service when selling new transmission service. New transmission service should be conditioned on the completion of these projects.

Planned Transmission Lines and Transformers:

Row ID Number	Expected In Service Date (mo/yr) (Note # 2 above)	MISO Area-SPG or Other Region	From:	To:	Circuit #	Voltage (kV)	Map Grid Location	Line Mile Estimates: Miles of Upgrade	Line Mile Estimates: Miles New	Line Mile Estimates: Total Miles	Summer Rating (MVA)	Need Estimate (SUM of Columns =100 %): Network/Native Load	Gen Interconnection	Transmission Service	Other (Explain)	Status (Note #1 above): In Service / Planned / Proposed	Reporting Source or ID	In Model (Y/N)	Estimated Cost (nominal current year $)	Group / Project Number
591	6/17/03	E-IOK	Kenton (to Wedonia 1200A Reactor 5% p.u. Z)			138	[redacted]				287		50		50	In Service	LGEE	?	$ 363,000	LGEE13
489	5/31/04	E-IOK	Beargrass	Jeffersonville Jct. (CIN)	1	138		0.2		0.2	258	100				Proposed	LGEE	Y	$ 52,000	LGEE2
490	5/31/04	E-IOK	Middletown		1	345/138		0.0			448	100				Proposed	LGEE	Y	$ 125,000	LGEE1
491	5/31/04	E-IOK	Middletown		2	345/138		0.0			448	100				Proposed	LGEE	Y	$ 125,000	LGEE1
492	5/31/04	E-IOK	Middletown		3	345/138		0.0			448	100				Proposed	LGEE	Y	$ 125,000	LGEE1
493	5/31/04	E-IOK	Middletown	Buckner	1	345		14.3		14.3	1066	100				Proposed	LGEE	Y	$ 5,000	LGEE3
494	5/31/04	E-IOK	Northside	Beargrass	1	138		0.2		0.2	258	100				Proposed	LGEE	Y	$ 52,000	LGEE2
495	5/31/04	E-IOK	Northside	Jeffersonville Jct. (CIN)	1	138		0.1		0.1	292	100				Proposed	LGEE	Y	$ 52,000	LGEE2
181	11/30/04	E-IOK	Lake Reba Tap	JK Smith (EKPC)	1	138	N11	10.3		10.3	251	50	50			Proposed	LGEE	Y	$ 5,000	LGEE4
156	5/31/05	E-IOK	Hardin County		2	345/138	M11		0.0		450	100				Proposed	LGEE	Y	$ 4,695,000	75
480	5/31/05	E-IOK	Middletown	Bluegrass Parkway	1	138	[redacted]		4.0	4.0	292	100				Proposed	LGEE	Y	$ 3,320,000	LGEE5
481	5/31/05	E-IOK	Northside	Beargrass	1	138		0.2		0.2	292	100				Proposed	LGEE	Y	$ 53,000	LGEE2
482	5/31/06	E-IOK	Brown North	Tyrone	1	138		20.1		20.1	179	100				Proposed	LGEE	Y	$ 331,000	LGEE7
483	5/31/06	E-IOK	Middletown		4	345/138	M11		0.0		450	50		50		Proposed	LGEE	Y	$ 4,695,000	LGEE13
484	5/31/07	E-IOK	Mill Creek	Manslick	1	138	[redacted]	6.8		6.8	193	100				Proposed	LGEE	Y	$ 85,000	LGEE8
485	11/30/07	E-IOK	Fawkes	Fawkes EKPC Tap	1	138		0.1		0.1	202	100				Proposed	LGEE	Y	$ 142,000	LGEE8
486	11/30/07	E-IOK	Pocket North 500/161		2	500/161	M11		0.0		450	100				Proposed	LGEE	Y	$ 3,416,000	LGEE9
487	12/31/08	E-IOK	Blue Lick	Bullitt County (EKPC)	1	161	[redacted]	8.2		8.2	235	0		100		Proposed	LGEE	Y	$ 1,180,000	14
488	12/31/08	E-IOK	Elizabethtown	Hardin County	1	138			1.3	1.3	224	50		50		Proposed	LGEE	Y	$ 1,106,000	14
139	12/31/08	E-IOK	Ghent	Owen County Tap	1	138		12.5		12.5	245	50		50		Proposed	LGEE	Y	$ 2,390,000	14
157	12/31/08	E-IOK	Mill Creek	Hardin County	1	345	M11		43.0	43.0	1195	50		50		Proposed	LGEE	Y	$ 60,139,000	14
159	12/31/08	E-IOK	Trimble County	Ghent	1	345	M10		2.8	2.8	598	0	100			Proposed	LGEE	Y	$ 4,598,000	14
160	12/31/08	E-IOK	Trimble County	Speed (Cinergy)	1	345	M10		2.8	2.8	1002	0	100			Proposed	LGEE	Y	$ 4,598,000	14
489	12/31/08	E-IOK	West Frankfort	Tyrone	1	138	[redacted]		10.2	10.2	224	50	50			Proposed	LGEE	Y	$ 9,003,000	14
490	12/31/08	E-IOK	West Lexington	Higby Mill	1	138			11.8	11.8	179	50		50		Proposed	LGEE	Y	$ 2,864,000	14
491	5/31/09	E-IOK	Brown CT	Danville North	1	138			19.0	19.0	245	100				Proposed	LGEE	Y	$ 9,793,000	LGEE10
492	5/31/09	E-IOK	Brown North	Higby Mill	1	138		16.0		16.0	224	100				Proposed	LGEE	Y	$ 20,000	LGEE11
145	5/31/09	E-IOK	Middletown	Plainview Tap	1	138		2.4		2.4	292	100				Proposed	LGEE	Y	$ 1,806,000	LGEE5
493	11/30/09	E-IOK	Lake Reba Tap	West Irvine Tap	1	161	N11	13.8		13.8	190	100				Proposed	LGEE	Y	$ 5,000	LGEE12

Form 2 of 2 for Reporting Substation Devices In the Baseline Reliability Study (MTEP-04)

Devices (capacitors, reactors, FACTS, etc):

Note #1: PLANNED projects are the preferred solution to an identified issue.
PROPOSED projects are a tentative solution to an identified issue.

Note #2: The projects in this list are projected for service on the date indicated. They are expected to be needed to meet existing committments including network and native load growth. Becuase there is always the possibility of delay in permitting and construction, or for modification or deferral of projects as system conditions change, Transmission Providers should not assume that these projects are In Service when selling new transmission service. New transmission service should be conditioned on the completion of these projects.

Note # 2 above									Need Estimate (SUM =100 %)				Status (Note #1 above)				
Expected In Service Date (mo/yr)	MISO Area [illegible] Region	Type Description	[illegible]	Location	[illegible] kV	[illegible]	[illegible] Rating [illegible]	[illegible] Location	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	Project Group Code

NONE FOR LG&E or KU

Transmission Project Construction Schedule

Current Timing	
03/04	Increase the summer normal/emergency capability of the terminal facilities for circuit 6663 at Clay and at Highland to at least 425/1021A.
04/04	Increase the capability of the 345 kV terminal equipment on the Middletown 345/138 kV transformer #3 to at least 870A and increase the capability of the 138 kV terminal equipment to at least 2170A.
04/04	Increase the capability of the 345 kV terminal equipment on the Middletown 345/138 kV transformer #5 to at least 870A and increase the capability of the 138 kV terminal equipment to at least 2170A.
04/04	Replace the 300 kcm CU line wire at Clark County associated with the Clark County-Sylvania section of the Clark County-Winchester 69 kV line with 750 kcm CU equipment.
04/04	Increase the capability of the 345 kV terminal equipment on the Middletown 345/138 kV transformer #4 to at least 870A and increase the capability of the 138 kV terminal equipment to at least 2170A.
05/04	Replace the 397 kcm ACSR conductor in the Clark County-Sylvania section of the Clark County-Winchester 69 kV line with 795 kcm ACSR conductor.
05/04	Increase the maximum operating temperature of the 266 kcm ACSR conductor in the AO Smith Tap to Camargo section of the Spencer Road to Clark County 69 kV line from its confirmed 130F limit to 155F.
05/04	Increase the summer normal/emergency capability of the terminal facilities for circuit 6669 at Ethel and at Dahlia to at least 586/1019A.
05/04	Upgrade the capability of the overload relaying for circuit 6669 at Dahlia to at least 1200A.
05/04	Increase the maximum operating temperature of the 2/0 CU conductor in the Rodburn to Morehead East section of the Rodburn to Farmers 69 kV line from its confirmed 150F rating to 160F.
05/04	Replace the 600A disconnects at Etown associated with breaker 34-614 with 1200A disconnects.
05/04	Increase the maximum operating temperature of the 266 kcm ACSR conductor in the Lake Reba-Richmond 69 kV line from 176F to 212F.
05/04	Increase the maximum operating temperature of the 1033 kcm ACSR conductor in the Northside-Beargrass 138 kV line (circuit 3883) from 176F to 212F.
05/04	Increase the summer emergency capability of the metering and relaying CTs at Middletown associated with circuit 4543 to at least 1593A.

Current Timing

Transmission Project Construction Schedule

05/04	Increase the maximum operating temperature of the 1033 kcm ACSR conductor in the Jeffersonville Jct.-Beargrass section of the Northside-Beargrass 138 kV line (circuit 3882) from 176F to 212F.
05/04	Close the Cane Run Switching-Mill Creek 69 kV line.
05/04	Replace the 636 kcm ACSR conductor in the Beargrass-River City Shredding section of circuit 6651 with 1272 ACSR or equivalent conductor.
05/04	Install a 69 kV, 19.8 MVAR capacitor at Tiptop #1.
05/04	Install a 69 kV, 48.0 MVAR capacitor at Walker.
05/04	Close the Tiptop 69 kV bus tie.
05/04	Increase the maximum operating temperature of the 1033 MCM ACSR conductor in the Northside-Jeffersonville Jct. section of the Northside-Beargrass 138 kV line (circuit 3882) from 176F to 212F.
06/04	Reconductor the Middletown-Finchville 69 kV line using 397 kcm ACSR conductor.
08/04	Replace the Rodburn 138/69 kV, 33 MVA transformer with a 60 MVA transformer.
09/04	Install a 69 kV, 13.5 MVAR capacitor at Leitchfield City.
11/04	Change the setting of the 2000A metering CT at Lake Reba Tap associated with the Lake Reba Tap-JK Smith EKPC 138 kV line from 1000A to 2000A.
11/04	Change the setting of the CTs associated with breaker 102-638 and the 69 kV transformer differential CTs at Fawkes from 1200A to 1500A. Replace the 600A disconnects associated with breaker 102-718 with 1200A equipment.
11/04	Install a 69 kV, 18.0 MVAR capacitor at Middlesboro #780.
12/04	Install a third 138/69 kV, 150 MVA transformer at Middletown.

Transmission Project Construction Schedule

Current Timing	
12/04	Construct 7.5 miles of 138 kV line from Middletown to Ford using 954 kcm ACSR conductor and operate this line at 69 kV.
12/04	Replace the 1272 AA conductor in the Middletown-Aiken 69 kV line (circuit 6657) with 2000 kcm conductor or equivalent. Reconductor the six-wired 336/636 kcm ACSR with six-wired 795 kcm ACSR.
12/04	Replace the 1272 AA bus and risers at Aiken associated with the Middletown-Aiken 69 kV line (6657) with 2000 kcm equipment or equivalent. Replace the 1272 AA bus, risers, and jumpers at Middletown with 2000 kcm equipment or equivalent. Increase the CT setting on the CT at Middletown from 1200A to 1500A.
03/05	Open the Goddard 138 kV interconnection.
03/05	Remove the 5% reactor from the Kenton-Rodburn 138 kV line and install it in the remaining Spurlock-Kenton 138 kV line..
03/05	Remove the Spurlock-Kenton circuit #2 138 kV line.
03/05	Close the East Bernstadt 69 kV interconnection with EKPC by looping the Pittsburg-Lancaster 69 kV line through EKPC's East Bernstadt station.
05/05	Install a 69 kV, 42.0 MVAR capacitor at Danville North.
05/05	Replace the 69kV, 600A switch 834-625 at Danville East with 1200A equipment.
05/05	Install a 69 kV, 33.0 MVAR capacitor at Shun Pike.
05/05	Construct 4.0 miles of 138 kV line from Middletown to Bluegrass Parkway using 1272 kcm ACSR conductor.
05/05	Increase the maximum operating temperature of the 397 kcm ACSR conductor in the Paris to Detroit Harvester Tap section of the Paris to Lexington Plant 69 kV line to 212F.
05/05	Construct 6 miles of 138 kV line using 556 kcm ACSR conductor from EKPC's Avon - Renaker 138 kV line to the 69 kV breaker station at Paris and install a 138-69 kV, 150 MVA transformer.
05/05	Install a 69 kV, 30 MVAR capacitor at Boone Avenue.

Transmission Project Construction Schedule

Current Timing

05/05 Increase the setting of the relay CT at Cane Run Switching Station associated with the Cane Run #6-Cane Run Switching 138 kV line (circuit 3826) to at least 1425A.

05/05 Replace the 336 kcm ACSR conductor in the Mud Lane-Smyrna 69 kV line with 556 kcm ACSR conductor. Open Fairmount-6662 Tap and close Fairmount bus tie switch.

05/05 Upgrade the operating limit of the Adams to Delaplain section of the Adams to Renaker/Millersburg 69 kV line from 176F to 212F.

05/05 Replace the 500 kcm CU risers and line wires associated with breaker 213-604 at Boonesboro North with 750 kcm CU equipment.

05/05 Increase the maximum operating temperature of the 556 kcm ACSR conductor in the Brown North-Tyrone 138 kV line from 176F to 212F.

05/05 Increase the maximum operating temperature of the 397 kcm ACSR conductor in the Fawkes-Richmond South section of the Fawkes-Okonite 69 kV line from 176F to 212F.

05/05 Install a 69 kV, 10.8 MVAR capacitor at Metal & Thermit.

05/05 Install a 69 kV, 16.8 MVAR capacitor at Fairmount.

05/05 Install a 69 kV, 7.2 MVAR capacitor at Paint Lick.

05/05 EKPC installs a 4% reactor at Avon on the Avon-Loudon Avenue 138 kV line.

05/05 Install a 69 kV, 45.0 MVAR capacitor at West Frankfort.

05/05 Install a 69 kV, 28.8 MVAR capacitor at Bardstown.

05/05 Construct a 138 kV line exit at Hardin County for EKPC.

05/05 Increase the maximum operating temperature of the 397 kcm ACSR conductor in the Lake Reba-Berea Tap section of the Lake Reba-Okonite 69 kV line to 212F.

Transmission Project Construction Schedule

Current Timing	
05/05	Increase the maximum operating temperature of the 3/0 ACSR in the Paris-Paris 12 kV section of the Paris-Millersburg 69 kV line from 176F to 212F.
05/05	Replace the 954 mcm ACSR conductor in the Cane Run #6-Cane Run Switching 138 kV line (circuit 3826) with 1272 mcm ACSR conductor or equivalent.
05/05	Replace the 600A disconnect at Shively associated with the Shively-Farnsley 69 kV line (circuit 6637) with 1200A equipment.
05/05	Install a 69 kV, 42.0 MVAR capacitor at Farley.
05/05	Install a 69 kV, 14.4 MVAR capacitor at Tunnel Hill.
05/05	Install a 69 kV, 30.0 MVAR capacitor at Blue Lick.
05/05	Install a 69 kV, 33.0 MVAR capacitor at Rogersville.
05/05	Replace the 266 kcm ACSR conductor in the Ohio County-Rosine Jct. section of the Ohio County-Leitchfield 69 kV line with 556 kcm ACSR conductor.
05/05	Increase the maximum operating temperature of the Fawkes-Fawkes Tap section of the Fawkes-Lake Reba Tap 138 kV line from 176F to 212F
05/05	Replace the 500 MCM CU terminal equipment at Hardinsburg associated with breaker 184-724 (Hardinsburg-Hardin County 138 kV) with 750 MCM CU equipment.
11/05	Change the 1000A CT ratio on the low-side of the Blue Lick 345/161 kV transformer to 1200A.
11/05	Install a 69 kV, 16.2 MVAR capacitor at Newtown.
11/05	Install a 69 kV, 51.0 MVAR capacitor at Pineville #192.
11/05	Install a 69 kV, 33.0 MVAR capacitor at Clark County.

Transmission Project Construction Schedule

Current Timing	
11/05	Replace the 600A disconnects at Middletown associated with the Middletown-Finchville 69 kV line (circuit 6601) with 1200A equipment.
11/05	Construct 7.5 miles of 138 kV line from St. Paul to AEP's Clinch River substation using 556 kcm ACSR conductor. Install a 138/69 kV, 120 MVA transformer at St. Paul.
11/05	Replace 600A breaker 116-604 at St. Paul (associated with the St. Paul-Bond 69 kV line) with a 1200A breaker.
05/06	Install a 138/69 kV, 150 MVA transformer at Danville North.
05/06	Replace the 500 kcm Cu bus associated with breaker 66-734 at Higby Mill with 750 kcm Cu.
05/06	Install a 69 kV line exit at Lebanon and construct 1.2 miles of 69 kV line from Lebanon to Lebanon Industrial using 397 kcm ACSR conductor.
05/06	Install a second 138-69 kV, 150 MVA transformer at Fawkes.
05/06	Reconductor the 397 kcm ACSR conductor in the Madisonville South Tap to McCoy Avenue section of the Madisonville loop with 556 kcm ACSR.
05/06	Replace the 300 kcm Cu bus, risers and line wire associated with breaker 69-604 at Richmond with 500 kcm Cu equipment.
05/06	Install a 69 kV, 26.4 MVAR capacitor at the KU Hodgenville #744 station.
05/06	Replace the West Cliff 138/69 kV, 93 MVA transformer with a 120 MVA transformer.
05/06	Reconductor the 266 kcm ACSR conductor in the Etown-Etown #5 69 kV line section using 397 kcm ACSR conductor.
05/06	Replace the 4/0 Cu wire associated with the air-break switch 847-615 in the Lexington Plant-Buchanan section of the Lexington Plant-Pisgah 69 kV line with 300 MCM Cu equipment.
05/06	Increase the maximum operating temperature of the 397 kcm ACSR conductor in the Sweet Hollow-North Corbin section of the Sweet Hollow-London 69 kV line to 212F.

Transmission Project Construction Schedule

Current Timing	
05/06	Install a fourth 345/138 kV, 450 MVA transformer at Middletown.
05/06	Increase the size of the London 69 kV capacitor to 30.6 MVARs.
05/06	Construct 4.2 miles of 69 kV line from Loudon Avenue to the Lakeshore/Bryant Road tap using 795 kcm ACSR conductor. Serve the Lakeshore and Bryant Road loads radially from this line.
05/06	Construct 1.5 miles of 69 kV line from Lebanon Industrial to Lebanon City using 397 kcm ACSR conductor. Serve Lebanon City on this radial from Lebanon.
05/06	Install a 69 kV, 64.8 MVAR capacitor at Dahlia.
05/06	Install a 69 kV, 18.0 MVAR capacitor at Cynthiana South.
05/06	Install a 69 kV, 33.6 MVAR capacitor at River Queen.
05/06	Install a 12.0 MVAR capacitor at Olin Corp.
11/06	Install a 69 kV, 6.6 MVAR capacitor at Pineville #722.
11/06	Construct 3.5 miles of 69 kV line from Pineville #722 to the Pineville to Calloway section of the Pineville to Rocky Branch 69 kV line using 556 kcm ACSR conductor. Operate Pineville #722 from the Pineville to Calloway 69 kV line section.
11/06	Replace the 600A disconnects associated with breaker 102-614 at Fawkes with 1200A equipment.
11/06	Replace the 556 kcm ACSR conductor in the Fawkes KU-Fawkes EKPC Tap section of the Fawkes-Lake Reba Tap 138 kV line with 795 kcm ACSR.
11/06	Install a 69 kV, 26.4 MVAR capacitor at Scott County.
11/06	Increase the winter emergency capability of the terminal equipment associated with the Pocket North-Pocket 161 kV line to at least 665A.

Current Timing

Transmission Project Construction Schedule

11/06 Replace the 1200A breaker 184-724 and associated wave trap at Hardinsburg and the 1200A breaker 178-714 and associated wave trap at Hardin County with 1600A equipment or higher.

11/06 Install a 69 kV, 28.8 MVAR capacitor at Versailles.

05/07 Construct 0.77 miles of 69 kV line from Danville North to the Atoka Tap using 397 kcm ACSR conductor utilizing available double circuit space on the Boyle Co to Danville North 69 kV line. Construct 2 miles of 69 kV line using 397 kcm ACSR from the Atoka Tap line to Minor Farm. Operate as a radial.

05/07 Replace the 600A air break switch 677-605 at Wilmore with a 1200A switch.

05/07 Replace the 600A disconnects associated with breaker 101-604 (Boyle County-Lancaster 69 kV line) at Boyle Co with 1200A equipment.

05/07 Install a third 138/69 kV, 112 MVA transformer at East Frankfort (use the spare 112 MVA removed from Loudon Avenue). Reconfigure the bus such that two transformers and two lines to Frankfort City stay in service during any contingency.

05/07 Increase the maximum thermal operating limit of the Kentucky State Hospital-Danville East section of the West Cliff-Boyle County 69 kV line to 212 degrees F.

05/07 Replace the 300 kcm Cu transformer wires associated with breakers 96-608 and 96-618 at Elihu with 500 kcm Cu wires.

05/07 Replace the 397 kcm ACSR conductor in the Sylvania-Parker Seal section of the Clark County-Winchester 69 kV line with 795 kcm ACSR conductor.

05/07 Replace the 600A bus and line CTs associated with breaker 199-624 at Winchester with 1200A equipment.

05/07 Change the setting of the 600A bus-side CT associated with breaker 18-614 at Spencer Road from 400A to 600A.

05/07 Replace the Spencer Road 138/69 kV, 56 MVA transformer with a 93 MVA transformer.

05/07 Replace the 600A disconnects 199-624B and 199-624L at Winchester with 1200A disconnects.

05/07 Replace the 266 kcm ACSR conductor in the Parkers Mill Tap-Parkers Mill section of the line tapping the Pisgah-Lexington Plant 69 kV line with 397 kcm ACSR conductor.

Transmission Project Construction Schedule

Current Timing

05/07 Change the setting of the 1200A line CT associated with breaker 135-604 at Clark County from 600A to 1200A. Replace the 500 MCM Cu bus and wires at Clark County with 750 MCM Cu equipment.

05/07 Construct 1.6 miles of 69 kV line from Ewington to AO Smith using 397 kcm ACSR conductor. Operate Ewington and AO Smith radially from Spencer Road.

05/07 Replace the 300 MCM Cu risers and line wire associated with breaker 199-624 at Winchester with 500 MCM Cu equipment.

05/07 Replace the Spencer Road 138/69 kV, 33 MVA transformer with a 93 MVA transformer. (Use the transformer removed from West Cliff). Operate the two transformers at Spencer Road in parallel.

05/07 Replace the bundled 1/0 Cu conductor in the Lexington Plant-Buchanan section of the Lexington Plant-Pisgah 69 kV line with 556 kcm ACSR conductor.

05/07 Replace the 4/0 Cu wire at Buchanan associated with the Buchanan-West High Tap section of the Lexington Plant-Pisgah 69 kV line with 300 MCM Cu equipment.

05/07 Increase the maximum operating temperature of the 266 kcm ACSR conductor in the Etown-Etown #2 Tap section of the Etown-Rogersville 69 kV line to 212F.

05/07 Install a 69 kV, 45 MVAR capacitor at Harrods Creek.

05/07 Replace the 600A disconnects associated with breaker 101-634 at Boyle County (Boyle County-Danville North 69 kV line) with 1200A equipment.

05/07 Increase the maximum operating temperature of the 266 kcm ACSR conductor in the Boyle County-Danville #1 section of the Boyle County-West Cliff 69 kV line from 176F to 212F.

05/07 Increase the setting of the meter CT associated with breaker 68-634 at Bonds Mill (Bonds Mill-North Springfield EKPC) from 600A to 800A.

05/07 Increase the maximum operating temperature of the 636 kcm ACSR conductor in the Mill Creek-Manslick 138 kV line (circuit 3834) from 176F to 180F.

05/07 Replace the 800A wave trap at Tyrone associated with the Brown North-Tyrone 138 kV line with a 1200A wave trap.

05/07 Increase the maximum verified operating temperature of the AO Smith Tap-Camargo section of the Spencer Road-Clark County 69 kV line to 212F.

Transmission Project Construction Schedule

Current Timing

05/07 Increase the size of the Eminence capacitor to 28.8 MVARs.

05/07 Install a 69 kV, 24.3 MVAR capacitor at Bardstown Industrial.

11/07 Install a 69 kV, 9.1 MVAR capacitor at Science Hill.

11/07 Replace breaker 18-614 at Spencer Road with a 1200A breaker.

11/07 Increase the maximum operating limit of the 266 kcm ACSR conductor in the Lake Reba-Waco section of the Lake Reba-West Irvine 69 kV line from 176F to 212F.

11/07 Increase the overload relay setting at Eastwood associated with the Eastwood-Simpsonville section of the Eastwood-Shelbyville 69 kV line from 720A to 840A.

11/07 Replace the 1200A breaker (102-724) and associated wave trap at Fawkes associated with the Fawkes-Lake Reba Tap 138 kV line with 1600A equipment.

11/07 Replace the 1200A meter CT at Fawkes associated with the Fawkes-Fawkes EKPC 138 kV line with 1600A equipment.

11/07 Replace the 161 kV, 800A wave trap associated with the Lake Reba Tap 161/138 kV transformer.

11/07 Replace the 600A meter CT at Etown associated with breaker 34-614 (Etown-Tharp EKPC 69 kV line) with equipment with a winter emergency capability of at least 967A.

11/07 Replace the 600A disconnects at Eastwood associated with the 6658 Tap-Eastwood section of circuit 6658 with 1200A equipment.

05/08 Construct 19 miles of 138 kV line from Brown CT to Danville North using 954 kcm ACSR conductor.

05/08 Replace the 138/69 kV, 93 MVA transformer at Bardstown with a 120 MVA transformer.

05/08 Reset the breaker CT on the transformer side of breaker 135-608 at Clark County from 600A to 1200A.

Transmission Project Construction Schedule

Current Timing	
05/08	Increase the rating of the Taylor County - Mile Lane section of the Taylor County to Green County 69 kV line by increasing the maximum operating temperature of the 266.8 kcm ACSR conductor to 212F.
05/08	Install a second 345/138 kV, 450 MVA transformer at Hardin County.
05/08	Increase the maximum operating temperature of the 397.5 kcm ACSR conductor in the Pineville to Pineville #722 section of the Pineville to Middlesboro 69 kV line to 100C.
05/08	Increase the CT ratio at Seminole for the Seminole to Floyd to Locust 69 kV line (6647) to 1200A.
05/08	Replace the 300 MCM Cu wires associated with breaker 34-614 at Etown with 500 MCM Cu equipment.
11/08	Replace the 69 kV, 600A switch 312-625 at Clinch Valley with a 1200A switch.
11/08	Replace the 336 MCM ACSR conductor in the Eastwood-Simpsonville section of the Eastwood-Shelbyville 69 kV line using 397 kcm ACSR conductor.
11/08	Move the Lebanon City 69 kV capacitor to Lebanon and increase the size to 28.8 MVars.
11/08	Replace the 500 MCM Cu bus at Fawkes associated with the Fawkes-Lake Reba Tap 138 kV line with 750 MCM Cu bus or equivalent.
11/08	Install a 69 kV, 13.5 MVAR capacitor at Williamsburg South.
11/08	Replace the 1200A breaker 213-608 at Boonesboro North associated with the Boonesboro North 138/69 kV transformer with a 1600A breaker.
05/09	Replace the 800A wave trap associated with breaker 152-724 at Brown North (Brown North-Pisgah 138 kV) with a 1200A wave trap.
05/09	Reconductor the Horse Cave Tap 69 kV line with 397.5 kcm ACSR conductor.
05/09	Reconductor the Dix Dam-Wilmore Tap section of the Dix Dam-Higby Mill 69 kV line with 556 kcm ACSR conductor.

Current Timing

Transmission Project Construction Schedule

05/09 Increase the maximum operating temperature of the 397 kcm ACSR conductor in the Bardstown-Bardstown Industrial Tap section of the Bardstown-East Bardstown EKPC 69 kV line from 80C to 100C.

05/09 Increase the maximum operating temperature of the 397 kcm ACSR conductor in the Etown to Etown #4 section of the Etown to Hodgenville EKPC 69 kV line to 212F.

05/09 Replace the 750 kcm CU line wire at West Cliff and the 750 kcm CU bus and line wire at Dix Dam associated with the West Cliff-Dix Dam 69 kV line with 1000 kcm CU equipment.

05/09 Reconductor the Middletown to Plainview Tap section of the Middletown to Beargrass 138 kV line with 1272 ACSR conductor.

05/09 Convert the Middletown-Ford 69 kV line to 138 kV and install a 138/69 kV, 150 MVA transformer at Ford.

05/09 Increase the maximum operating temperature of the 397 kcm ACSR conductor in the North Madison EKPC-Spears B section of the Fawkes-Higby Mill 69 kV line from 150F to 155F.

05/09 Increase the maximum operating temperature of the 500 kcm Cu conductor in the Blue Lick-Bullitt County 161 kV line from 176F to 212F.

05/09 Increase the capability of the metering and relaying CTs at Mill Creek associated with circuit 3855 to at least 300A.

05/09 Replace the 138/69 kV, 112 MVA transformer at Higby Mill between breakers 66-708 and 66-608 with a 150 MVA transformer.

05/09 Replace the 397 kcm ACSR conductor in the Fawkes-Richmond South section of the Fawkes-Okonite 69 kV line using 556 kcm ACSR conductor.

05/09 Increase the maximum unverified operating temperature of the 397 kcm ACSR conductor in the Elihu-Somerset #3 section of the Elihu (96-624)-Somerset North 69 kV line from 176F to 212F.

05/09 Install a third 138/69 kV, 60 MVA transformer at Carrollton.

05/09 Increase the maximum operating temperature of the #2 1X Cu conductor in the Lawrence Tap-Lawrence section of the Carrollton-Eminence 69 kV line from 176F to 212F.

05/09 Change the setting of the bus CT at Boyle County associated with the Boyle County-Danville North 69 kV line from 600A to at least 800A.

Transmission Project Construction Schedule

Current Timing	
05/09	Replace the 600A disconnect 676-2 in the 6676 Tap-Blue Lick RECC section of the South Park-Mud Lane 69 kV line (circuit 6676) with 1200A equipment.
05/09	Increase the maximum operating temperature of the 795 MCM AA conductor in the Watterson-Nachand 69 kV line (circuit 6667) from 176F to 212F.
05/09	Install a 69 kV, 12.6 MVAR capacitor at Hunters Bottom.
05/09	Install a second 138/69 kV, 120 MVA transformer at Algonquin.
05/09	Change the CT settings associated with breaker 155-714 at Bardstown (Bardstown-Brown CT) from 600A to 800A.
05/09	Replace the 397 kcm ACSR conductor in the Vaksdahl Avenue-Danville Industrial Tap section of the Boyle County-Lancaster 69 kV line with 556 kcm ACSR conductor.
05/09	Increase the maximum operating temperature of the Fawkes Tap-Lake Reba Tap section of the Fawkes-Lake Reba Tap 138 kV line from 176F to 212F.
11/09	Replace the Pineville 161/69 kV, 93 MVA transformer with a 120 MVA unit.
11/09	Change the setting of the 1200A line CT on breaker 71-624 at Imboden from 600A to 800A.
11/09	Install a 69 kV, 6.0 MVAR capacitor at Union Underwear.
11/09	Change the setting of the 161 kV bus CT associated with breaker 162-804 at Lake Reba Tap from 600A to 800A.
11/09	Change the setting of the bus CT on breaker 65-624 at Tyrone from 600A to 800A.
11/09	Change the setting of the bus CT associated with breaker 162-724 at Lake Reba Tap from 1200A to 1500A.
11/09	Reconductor the 266 kcm ACSR conductor in the Lake Reba-Waco section of the Lake Reba-West Irvine 69 kV line with 397 kcm ACSR conductor.

Transmission Project Construction Schedule

Current Timing	
11/09	Change the CT setting of the bus CT associated with breaker 162-804 at Lake Reba Tap from 600A to 800A.
11/09	Change the CT settings at Fawkes and Richmond associated with the Fawkes-Richmond 69 kV line from 800A to 1000A.
12/09	Construct approximately 43 miles of 345 kV line from Mill Creek to Hardin County using bundled 954 kcm ACSR conductor.
12/09	Construct 11.8 miles of 138 kV line between West Lexington and Higby Mill using 556 kcm ACSR conductor.
12/09	Construct 10.2 miles of 138 kV line between West Frankfort and Tyrone using 795 kcm ACSR conductor.
12/09	Reconductor the Ghent-Owen County Tap section of the Ghent-Scott County 138 kV line using 954 kcm ACSR conductor.
12/09	Construct a 138 kV line between Etown and Hardin County using 795 kcm ACSR conductor.
12/09	Install two 345 kV line exits at Trimble Co and build 2.8 miles of double circuit 345 kV line to Cinergy's Ghent to Speed 345 kV line.
05/10	Replace the 1200A disconnects 178-718T and 178-718B at Hardin County with 2000A equipment.
05/10	Replace the 500 kcm CU bus and line wire at Etown associated with the Hardin County-Etown 138 kV line with 750 kcm CU equipment.
05/10	Replace breaker 127-638 at Haefling associated with the Haefling 138/69 kV transformer with 1600A equipment. Reset the low-side transformer CT to 1300A.
05/10	Increase the maximum operating temperature of the 795 kcm ACSR conductor in the P&G-Race Street section of the Lexington Plant-Race Street 69 kV line from 130F to 135F.
05/10	Replace the 1033 kcm ACSR conductor in the Northside-Jeffersonville Jct. section of the Northside-Beargrass 138 kV line (circuit 3882) with bundled 954 kcm ACSR conductor.
05/10	Install a 69 kV, 39.6 MVAR capacitor at Paris.

Transmission Project Construction Schedule

Current Timing

05/10 Replace the 397 kcm ACSR conductor in the Laurel County EKPC-Hopewell section of the Laurel County EKPC-Sweet Hollow 69 kV line using 556 kcm ACSR.

05/10 Install a 69 kV, 16.8 MVAR capacitor at Delaplain.

11/10 Install a 69 kV, 23.4 MVAR capacitor at Gorge.

05/11 Replace the 138-69 kV, 112 MVA transformer at Danville North with a 150 MVA transformer.

05/11 Upgrade the maximum operating temperature of the conductor in the Carrolton to Metal Thermistor section of the Carrollton to Owen Co 69 kV line from 176F to 212F.

05/11 Install a 138/69 kV, 120 MVA transformer at Hardin County.

05/11 Increase the maximum operating temperature of the 266 kcm ACSR conductor in the Somerset EKPC to Somerset South section of the Somerset EKPC-Sewellton EKPC 69 kV line to 100C.

05/11 Replace the 161/69 kV, 56 MVA transformer at Taylor County with a 90 MVA unit.

05/11 Replace the 2000 kcm AA underground conductor in the Ethel-Dahlia 69 kV line (circuit 6669) with overhead 954 kcm ACSR.

05/11 Increase the size of the Bardstown City capacitor by 2.4 MVARs.

05/12 Install 138 kV breakers on the Lebanon 138-69 kV transformers.

05/12 Replace the 138/69 kV, 93 MVA transformer at Clark County with a 150 MVA transformer.

05/12 Increase the maximum operating temperature of the 266 kcm ACSR conductor in the Greensburg-Campbellsville EKPC section of the Green County EKPC-Taylor County 69 kV line from 176F to 200F.

05/12 Replace the 1033 kcm ACSR conductor in the Northside-Beargrass 138 kV line (circuit 3883) with bundled 954 kcm ACSR conductor.

Current Timing

Transmission Project Construction Schedule

05/12	Install 138 kV breakers at Pisgah and install a second Pisgah 138/69 kV, 112 MVA transformer. (Use transformer removed from Higby Mill).
05/12	Close switch 609-605 at Delaplain to operate the Delaplain-Delaplain Tap 69 kV line section normally-closed.
05/12	Construct a 69 kV circuit from Middletown to Collins using the open circuit on the Middletown to Ford double-circuit towers.
11/12	Replace the 161-69 kV, 56 MVA transformer at Beattyville with a 90 MVA unit.
11/12	Energize the second Brown North-Pineville 345 kV circuit.
05/13	Install a second 345/138 kV, 450 MVA transformer at Brown North
05/13	Reconductor the 266 kcm ACSR conductor in the Adams to Toyota South 138 kV line with 556 kcm ACSR conductor.
05/13	Reconductor the 266 kcm ACSR conductor in the Green County EKPC-Greensburg KU section of the Green County EKPC-Taylor County 69 kV line using 397 kcm ACSR conductor.
05/13	Increase the maximum operating temperature of the 636 kcm ACSR conductor in the Oxmoor to Breckenridge 69 kV line (6653) to 100C.
05/13	Increase the CT ratios at Oxmoor and Breckenridge for the Oxmoor to Breckenridge 69 kV line (6653) to 1200A.
05/13	Replace the 600A disconnects associated with breaker 66-644 at Higby Mill with 1200A disconnects.
05/13	Install a 69 kV, 18 MVAR capacitor at Camargo.
05/13	Replace the 1200A disconnects associated with breaker 176-714 at Loudon Avenue with 1600A equipment.
05/13	Replace the 266 kcm ACSR conductor in the Adams-Delaplain Tap section of the Adams-Millersburg 69 kV line with 397 kcm ACSR conductor.

Transmission Project Construction Schedule

Current Timing	
05/13	Construct 2 miles of 138 kV line from Kosmos Cement to Knob Creek and install three 138 kV breakers at Knob Creek.
05/13	Reconductor the Avon EKPC-Loudon Avenue 138 kV line using bundled 556 kcm ACSR conductor.
05/13	Replace the 1000 MCM Cu bus at Loudon Avenue associated with the Avon EKPC-Loudon Avenue 138 kV line with 2" AL tube or equivalent.
05/13	Replace the 266 kcm ACSR conductor in the Rosine Jct.-Caneyville Jct. section of the Ohio County-Leitchfield 69 kV line with 556 kcm ACSR conductor.